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The Risk Management Implications of NUREG-1150 Methods and Results

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Prepared by
A. L. Camp, K. J. Maloney, T. T. Sype

Sandia National Laboratories
Albuquerque, NM 87185

Division of Systems Research
Office of Nuclear Regulatory Research
U.S. Nuclear Regulatory Commission
Washington, DC 20555
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ABSTRACT

This report describes the potential uses of NUREG-1150 and similar Probabilistic Risk Assessments (PRAs) in NRC and industry risk management programs. NUREG-1150 uses state-of-the-art PRA techniques to estimate the risk from five nuclear power plants. The methods and results produced in NUREG-1150 provide a framework within which current risk management strategies can be evaluated, and future risk management programs can be developed and assessed. While the development of plant-specific risk management strategies is beyond the scope of this document, examples of the use of the NUREG-1150 framework for identifying and evaluating risk management options are presented. All phases of risk management from prevention of initiating events through reduction of off-site consequences are discussed, with particular attention given to the early phases of accidents.

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ACRONYMS AND INITIALISMS

ASEP	Accident Sequence Evaluation Program
ADV	atmospheric dump valve
AFW	auxiliary feedwater
ADS	automatic depressurization system
ATWS	anticipated transient without scram
BWR	boiling water reactor
CHR	containment heat removal
CDF	core damage frequency
CCW	component cooling water
CRD	control rod drive
DG	diesel generator
ESW	emergency service water
ECCS	emergency core cooling system
EDG	emergency diesel generator
ECW	emergency cooling water
EOP	emergency operating procedures
EPG	emergency procedures guide
GE	General Electric
GTG	gas turbine generator
HPCS	high pressure core spray
HPI	high pressure injection
HPSW	high pressure service water
HPCI	high pressure coolant injection
ILRT	integrated leak rate test
LOSP	loss of offsite power
LPCS	low pressure core spray
LPCI	low pressure coolant injection
NRC	Nuclear Regulatory Commission
NPSH	net positive suction head
NRAC	non-recovery of AC power
OP	operating procedures
PRA	probabilistic risk assessment
PRUEP	Phenomenology and Risk Uncertainty Evaluation Program
PORV	power-operated relief valve
PCV	primary containment venting
PWR	pressurized water reactor

ACRONYMS AND INITIALISMS (Cont.)

PDS	plant damage state
PCS	power conversion system
RCP	reactor coolant pump
RCIC	reactor core isolation cooling
RWST	refueling water storage tank
RHR	residual heat removal
SARRP	Severe Accident Risk Reduction Program
SBO	station blackout
SRV	safety relief valve
SLC	standby liquid cooling
SPDS	safety parameter display system
SBGT	standby gas treatment system
SETS	set equation transformation system
SBOB	station blackout-battery depletion
SBOL	station blackout-loss of feedwater
SBOS	station blackout-RCP seal LOCA
SBOQ	station blackout-stuck-open PORV
SG	steam generators
TEMAC	top event matrix analysis code
TMI	Three Mile Island
TW	transient initiating event followed by loss of RHR
UPS	uninterruptible power supplies

FOREWORD

This is one of numerous documents that support the preparation of the NUREG-1150 document by the NRC Office of Nuclear Regulatory Research. Figure 1 illustrates the front-end documentation. There are three interfacing programs at Sandia National Laboratories performing this work: the Accident Sequence Evaluation Program (ASEP), the Severe Accident Risk Reduction Program (SARRP), and the Phenomenology and Risk Uncertainty Evaluation Program (PRUEP). The Zion PRA was performed at Idaho National Engineering Laboratories and Brookhaven National Laboratories.

Table 1 is a list of the original primary documentation and the corresponding revised documentation. There are several items that should be noted. First, in the original NUREG/CR-4550 report, Volume 2 was to be a summary of the internal analyses. This report was deleted. In Revision 1, Volume 2 now is the expert judgment elicitation covering all plants.

Volumes 3 and 4 include external events analyses for Surry and Peach Bottom. External events for Sequoyah, Grand Gulf and Zion will be analyzed in follow-up studies after NUREG-1150 is published.

The revised NUREG/CR-4551 covers the analysis included in the original NUREG/CR-4551 and NUREG/CR-4700. However, it is different from NUREG/CR-4550 in that the results from the expert judgment elicitation are given in four parts to Volume 2 with each part covering one category of issues. The accident progression event trees are given in the appendices for each of the plant analyses.

Originally, NUREG/CR-4550 was published without the designation "Draft for Comment." Thus, the final revision of NUREG/CR-4550 is designated Revision 1. The label Revision 1 is used consistently on all volumes, including Volume 2 which was not part of the original documentation. NUREG/CR-4551 was originally published as a "Draft for Comment" so, in its final form, no Revision 1 designator is required to distinguish it from the previous documentation.

There are several other reports published in association with NUREG-1150. These are:

NUREG/CR-5032, SAND87-2428, Modeling Time to Recovery and Initiating Event Frequency for Loss of Off-site Power Incidents at Nuclear Power Plants, R. L. Iman and S. C. Hora, Sandia National Laboratories, Albuquerque, NM, January 1988.

NUREG/CR-4840, SAND88-3102, Methodology for External Event Screening Quantification - RMIEP Methodology, M. P. Bohn and J. A. Lambright, Sandia National Laboratories, Albuquerque, NM, July 1989.

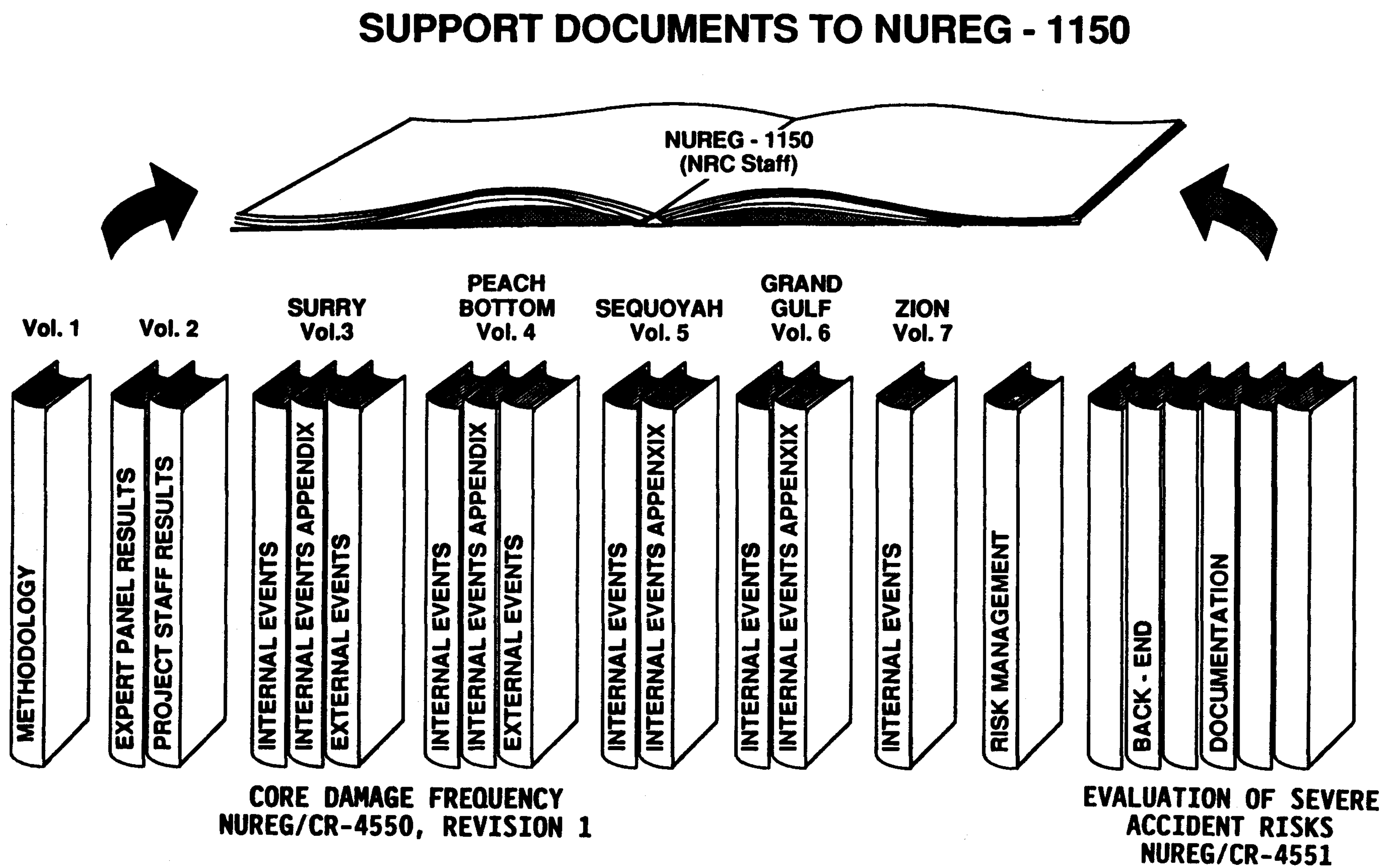

FIGURE 1. DOCUMENTATION FOR NUREG-1150.

Table 1.
NUREG-1150 Analysis Documentation

Original Documentation

NUREG/CR-4550
Analysis of Core Damage Frequency From Internal Events

Volume	1	Methodology
	2	Summary (Not Published)
	3	Surry Unit 1
	4	Peach Bottom Unit 2
	5	Sequoyah Unit 1
	6	Grand Gulf Unit 1
	7	Zion Unit 1

NUREG/CR-4551
Evaluation of Severe Accident Risks and the Potential for Risk Reduction

Volume	1	Surry Unit 1
	2	Sequoyah Unit 1
	3	Peach Bottom Unit 2
	4	Grand Gulf Unit 1

NUREG/CR-4700
Containment Event Analysis for Potential Severe Accidents

Volume	1	Surry Unit 1
	2	Sequoyah Unit 1
	3	Peach Bottom Unit 2
	4	Grand Gulf Unit 1

Revised Documentation

NUREG/CR-4550, Revision 1
Analysis of Core Damage Frequency

Volume	1	Methodology	
	2	Part 1	Expert Judgment Elicit. Expert Panel
		Part 2	Expert Judgment Elicit.--Project Staff
	3	Part 1	Surry Unit 1 Internal Events
		Part 2	Surry Unit 1 Internal Events App.
		Part 3	Surry Unit 1 External Events
	4	Part 1	Peach Bottom Unit 2 Internal Events
		Part 2	Peach Bottom Unit 2 Internal Events App.
		Part 3	Peach Bottom Unit 2 External Events
	5	Part 1	Sequoyah Unit 1 Internal Events
		Part 2	Sequoyah Unit 1 Internal Events App.
	6	Part 1	Grand Gulf Unit 1 Internal Events
		Part 2	Grand Gulf Unit 1 Internal Events App.
	7	Zion Unit 1 Internal Events	

NUREG/CR-4551, Evaluation of Severe Accident Risks

Volume	1	Methodology	
	2	Part 1	Expert Judgment Elicit.--In-vessel
		Part 2	Expert Judgment Elicit.--Containment
		Part 3	Expert Judgment Elicit.--Structural
		Part 4	Expert Judgment Elicit.--Source-Term
		Part 5	Expert Judgment Elicit.--Supp. Calc.
		Part 6	Expert Judgment Elicit.--Proj. Staff
		Part 7	Expert Judgment Elicit.--Supp. Calc.
		Part 8	Expert Judgment Elicit.--MACCS Input
	3	Part 1	Surry Unit 1 Anal. and Results
		Part 2	Surry Unit 1 Appendices
	4	Part 1	Peach Bottom Unit 2 Anal. and Results
		Part 2	Peach Bottom Unit 2 Appendices
	5	Part 1	Sequoyah Unit 2 Anal. and Results
		Part 2	Sequoyah Unit 2 Appendices
	6	Part 1	Grand Gulf Unit 1 Anal. and Results
		Part 2	Grand Gulf Unit 1 Appendices
	7	Part 1	Zion Unit 1 Anal. and Results
		Part 2	Zion Unit 1 Appendices

NUREG/CR-4772, SAND86-1996, Accident Sequence Evaluation Program Human Reliability Analysis Procedure, A. D. Swain III, Sandia National Laboratories, Albuquerque, NM, February 1987.

NUREG/CR-5263, SAND88-3100, The Risk Management Implications of NUREG-1150 Methods and Results, A. L. Camp et al., Sandia National Laboratories, Albuquerque, NM, September 1989.

A Human Reliability Analysis for the ATWS Accident Sequence with MSIV Closure at the Peach Bottom Atomic Power Station, A-3272, W. J. Luckas, Jr. et al., Brookhaven National Laboratory, Upton, NY, 1986.

Any related supporting documents to the back-end NUREG/CR-4551 analyses are delineated in NUREG/CR-4551. A complete list of the revised NUREG/CR-4550, Revision 1 volumes and parts is given below.

General

NUREG/CR-4550, Revision 1, Volume 1, SAND86-2084, Analysis of Core Damage Frequency: Methodology Guidelines for Internal Events.

NUREG/CR-4550, Revision 1, Volume 2, Part 1, SAND86-2084, Analysis of Core Damage Frequency: Expert Judgment Elicitation on Internal Events Issues - Expert Panel.

NUREG/CR-4550, Revision 1, Volume 2, Part 2, SAND86-2084, Analysis of Core Damage Frequency: Expert Judgment Elicitation on Internal Events Issues - Project Staff.

Parts 1 and 2 of Volume 2, NUREG/CR-4550 were published in one binder. This volume was published in April 1989 and distributed in May 1989 with an incorrect title, i.e., Analysis of Core Damage Frequency from Internal Events: Expert Judgment Elicitation, without the Revision 1 designation. The complete, correct title is: NUREG/CR-4550, Revision 1, Volume 2, SAND86-2084, Analysis of Core Damage Frequency: Expert Judgment Elicitation on Internal Events Issues.

Surry

NUREG/CR-4550, Revision 1, Volume 3, Part 1, SAND86-2084, Analysis of Core Damage Frequency: Surry Unit 1 Internal Events.

NUREG/CR-4550, Revision 1, Volume 3, Part 2, SAND86-2084, Analysis of Core Damage Frequency: Surry Unit 1 Internal Events Appendices.

NUREG/CR-4550, Revision 1, Volume 3, Part 3, SAND86-2084, Analysis of Core Damage Frequency: Surry Unit 1 External Events.

Peach Bottom

NUREG/CR-4697, EGG-2464, Containment Venting Analysis for the Peach Bottom Atomic Power Station, D. J. Hansen, et al., Idaho National Engineering Laboratory (EG&G Idaho, Inc.) February 1987.

NUREG/CR-4550, Revision 1, Volume 4, Part 1, SAND86-2084, Analysis of Core Damage Frequency: Peach Bottom Unit 2 Internal Events.

NUREG/CR-4550, Revision 1, Volume 4, Part 2, SAND86-2084, Analysis of Core Damage Frequency: Peach Bottom Unit 2 Internal Events Appendices.

NUREG/CR-4550, Revision 1, Volume 4, Part 3, SAND86-2084, Analysis of Core Damage Frequency: Peach Bottom Unit 2 External Events.

Sequoyah

NUREG/CR-4550, Revision 1, Volume 5, Part 1, SAND86-2084, Analysis of Core Damage Frequency: Sequoyah Unit 1 Internal Events.

NUREG/CR-4550, Revision 1, Volume 5, Part 2, SAND86-2084, Analysis of Core Damage Frequency: Sequoyah Unit 1 Internal Events Appendices.

Grand Gulf

NUREG/CR-4550, Revision 1, Volume 6, Part 1, SAND86-2084, Analysis of Core Damage Frequency: Grand Gulf Unit 1 Internal Events.

NUREG/CR-4550, Revision 1, Volume 6, Part 2, SAND86-2084, Analysis of Core Damage Frequency: Grand Gulf Unit 1 Internal Events Appendices.

Zion

NUREG/CR-4550, Revision 1, Volume 7, EGG-2554, Analysis of Core Damage Frequency: Zion Unit 1 Internal Events.

Acknowledgements

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Several people were involved in support roles such as Timothy Wheeler for assistance with the TEMAC computer code and Emily Preston for preparation of documentation. Their efforts are greatly appreciated.

SUMMARY

1. Introduction

For the past few years, the Nuclear Regulatory Commission (NRC) has been preparing NUREG-1150, which examines the risk from five nuclear power plants. NUREG-1150 effectively replaces the 1975 Reactor Safety Study [1] and provides the technical basis for a wide range of regulatory initiatives. Late in the NUREG-1150 program, an effort was undertaken to examine the implications of NUREG-1150 and similar Probabilistic Risk Assessments (PRAs) for risk management initiatives. This report describes the findings of this limited-scope analysis effort.

Before describing the technical results of this work, it is necessary to define the objectives and scope of risk management, as related to NUREG-1150. Risk management programs at nuclear power plants have two basic objectives:

1. Minimize the public health risk from nuclear power plants, and

2. Provide the capability for operators and decision-makers to effectively respond to and thereby reduce the probability and consequences of severe accidents.

In practice, risk management can be divided into five separate, but interrelated, phases:

1. Prevention of accident initiators (reliability management),

2. Prevention of core damage (accident management),

3. Implementation of an effective emergency response (emergency response management),

4. Prevention of vessel breach and mitigation of radionuclide releases from the reactor coolant system (accident management), and

5. Retention of fission products in the containment and other surrounding buildings (accident management).

"Accident Management" is a term that is often used in place of "risk management"; however the former is usually applied to the late stages of phase 2 and phases 3 through 5. Thus, risk management is a more comprehensive approach.

This report presents a risk-based methodology for identifying and evaluating risk management options for each of the five phases above. Examples ni which this methodology is applied to the internal events analysis of four NUREG-1150 plants (Peach Bottom, Grand Gulf, Surry and Sequoyah) are described. The report and the methods contained therein are intended for persons with expertise in PRA technology and knowledge of methods and results contained in NUREG-1150 and the supporting contractor documents. While the development of comprehensive, plant-specific risk management strategies is beyond the scope of this report, examples of the use of these methods for identifying and evaluating risk management options are presented. Therefore, risk management analysts are provided with a demonstrated technical approach for future plant-specific studies.

The quantitative examples in this report focus on Phase 1 and 2 risk management. Primarily qualitative discussions of the other phases are provided.

2. Approach

Severe reactor accidents involve extremely complex system and phenomenological responses that are often nonintuitive. When developing and evaluating risk management options it is important to understand how a particular action may affect other portions of the accident progression. The PRA methods developed for NUREG-1150 provide an integrated analysis framework that can be used to evaluate the potential ramifications of a certain action over a wide range of possible outcomes. These methods provide far more depth and breadth than has been included in previous PRAs. All five phases of risk management can be examined using such an integrated framework.

The application of the NUREG-1150 methods to the evaluation of risk management strategies is summarized in Figure S.1 and discussed in more detail later in the report. This framework provides the capability to compare various strategies based on selected risk measures, such as health and economic risk. Risk is not the only measure of the effectiveness of risk management strategies. Cost and practicality of implementation are also important. However, a PRA framework with all of the enhancements of NUREG-1150 provides a powerful tool for supplementing current approaches.

A key area where the NUREG-1150 methods can contribute to risk management is in the treatment of uncertainties. PRA results can supplement detailed deterministic calculations by identifying alternative outcomes for the important accident sequences. By identifying these alternatives, along with their frequency of occurrence, the operators are made aware of the uncertainty in severe accident progression and the need for sufficient flexibility to deal with a spectrum of potential outcomes.

3. Evaluation of Future Risk Management Strategies

This section addresses the use of NUREG-1150 methods in developing potential risk management strategies which address the five interrelated phases identified earlier. The approach to be used for each phase is discussed, and quantitative examples are presented for Phase 1 and 2 strategies. A general discussion of the approach is presented for the other phases.

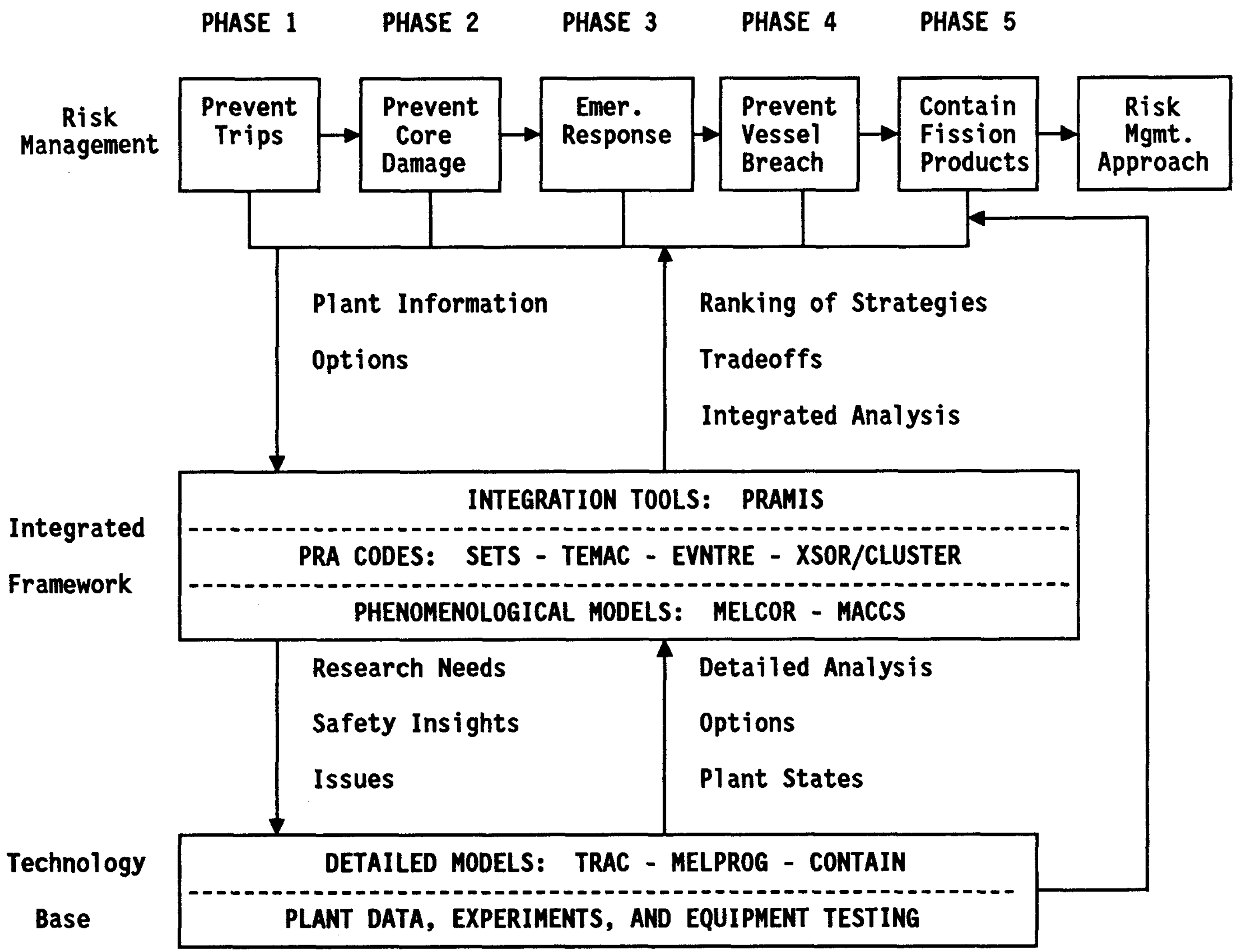

Figure S.1. Risk Management Analysis Framework.

An integrated and flexible approach to risk management is needed due to the many interrelationships and dependencies that exist among the five phases and because of the uncertainty present in the system and phenomenological responses during a particular severe accident. The development of system and phenomenological models to support risk management is relatively straightforward. However, implementation of risk management strategies in the form of additional emergency procedures is more complex. Of particular concern is the development of procedures that are sufficiently flexible to deal with the range of possible accident progression outcomes.

The uncertainties in accident progression clearly indicate the need for symptom and function oriented procedures, rather than event based procedures. The industry has moved rapidly in that direction since TMI, including the development of advanced control room displays. The current test, maintenance, and operating procedures in place at most plants are generally good with respect to the first two phases of risk management. While additional work is still needed in these areas, it is the late phases of a severe accident that need the most attention and development.

A key aspect of managing severe accidents is the availability of reliable monitoring instruments and displays. In developing current risk management plans, it should be recognized that much of the available instrumentation is not designed to operate in the severe pressure, temperature, and radiation environments that may occur in the risk-dominant accident sequences.

It should be noted that the options discussed in this section are not to be considered as necessary plant changes, but rather examples of how PRA techniques can be used to identify and evaluate risk management options.

Phase 1 - Prevention of Accident Initiators

PRA tools are extremely useful in identifying important accident initiators and evaluating methods for reducing their importance. Industry trip reduction programs have already had an impact in this area. However, PRA tools can identify and evaluate areas for future improvements. The first step in reducing the impact of accident initiators is to identify the initiators that are important to risk, which is a straightforward process with the availability of a PRA. It is extremely important to recognize that the initiators most significant to risk are not usually those that are the most frequent, so merely reducing the total number of trips may not significantly reduce plant risk. Given that the important initiators are identified, the next step is to ascertain the root causes of those failures. Before the frequency of these events can be reduced, the reasons for their occurrence must be understood.

The next step is to identify options for reducing the frequency of important initiators, which may include:

1. Improvements to operating procedures

2. Improvements to test and maintenance procedures

3. Changes to technical specifications and limiting conditions for operation

4. Changes to hardware and system configurations

5. Adding or revising automatic "early time" responses

The final step in this process is to evaluate the potential risk reduction of each option using the PRA framework. Options can be evaluated in terms of their impact on the core damage frequency (CDF) and/or overall risk. A Phase 1 option examined for the Surry plant concerns the addition of a diesel generator. The overall Surry CDF is dominated by the contribution from station blackout sequences; therefore, strategies to enhance the reliability of the onsite AC power systems significantly affect the total CDF and risk. The addition of an independent diesel generator would not prevent the loss of offsite power (LOSP) initiator, but would provide immediate accident mitigation and thus decrease the frequency of the station blackout sequences.

Phase 2 - Prevention of Core Damage

The occurrence of an initiating event leads to challenges to the plant safety systems. Operators must bring the plant to a subcritical condition with adequate water inventory and decay heat removal. At many Boiling Water Reactors (BWRs), for example, procedures are based on response to four critical parameters:

1. Reactor power

2. Containment pressure

3. Reactor vessel water level

4. Reactor pressure

This approach eliminates the need to precisely identify the particular accident sequence in progress. However, even with this approach, there are uncertainties regarding the phenomenology of particular accidents and the response of the control room instruments to certain off-normal events. Also, the response to a particular event is likely to involve the use of systems that are tested frequently, but that are rarely used in actual operation. Once the event has started, the operators may see control room indications that they have never encountered before. Thus, the quality of both the hardware and operator training is important.

From an analysis standpoint, the evaluation of phase 2 options is similar to the evaluation of phase 1 options. This process includes the identification of important accident sequences, hardware failures and human errors within these sequences that contribute most to the CDF, and the root causes of these failures. Enhanced risk management options can then be proposed, which may include:

1. Improvements to operating procedures

2. Improved operator training and staffing

3. Improved test and maintenance procedures for safety-related systems

4. Hardware modifications

As mentioned earlier, the dominant sequences at the Surry plant from a core damage frequency standpoint involve station blackout. Among the significant contributors to the CDF are: (1) failure to recover offsite power prior to battery depletion, (2) failure of the diesel generators, and (3) an induced reactor coolant pump seal loss of coolant accident (LOCA). Using the NUREG-1150 methodology, three Phase 2 options for Surry were evaluated that address these particular failures:

1. Extending the battery life

2. The use of an onsite gas turbine generator to recover from station blackout conditions; two such generators are present at the Surry site but are not currently available for short-term use

3. The addition of improved reactor coolant pump seal material to reduce the frequency of seal LOCA events

Figure S.2 shows the effect of the selected Phase 1 and 2 risk management strategies on the CDF of Surry. The core damage frequency reduction factor attributable to each strategy is shown, calculated by dividing the the current plant CDF by the new plant CDF (with the strategy incorporated).

Phase 3 - Implementation of Effective Emergency Response

Emergency response involves actions outside the plant before and after an accident to reduce public exposure to radiation. A specific emergency response will be comprised of some combination of evacuation, sheltering, decontamination, and interdiction strategies. Emergency response can be very site-specific, and is strongly influenced by population density, road systems, weather conditions, and interactions with and between local and state governments. Some existing emergency response strategies consider alternatives such as graded response or sheltering. There is very little guidance concerning correlation of the emergency response with the anticipated progression of the accident. For example, the relationship between containment failure or venting and evacuation strategies should be considered.

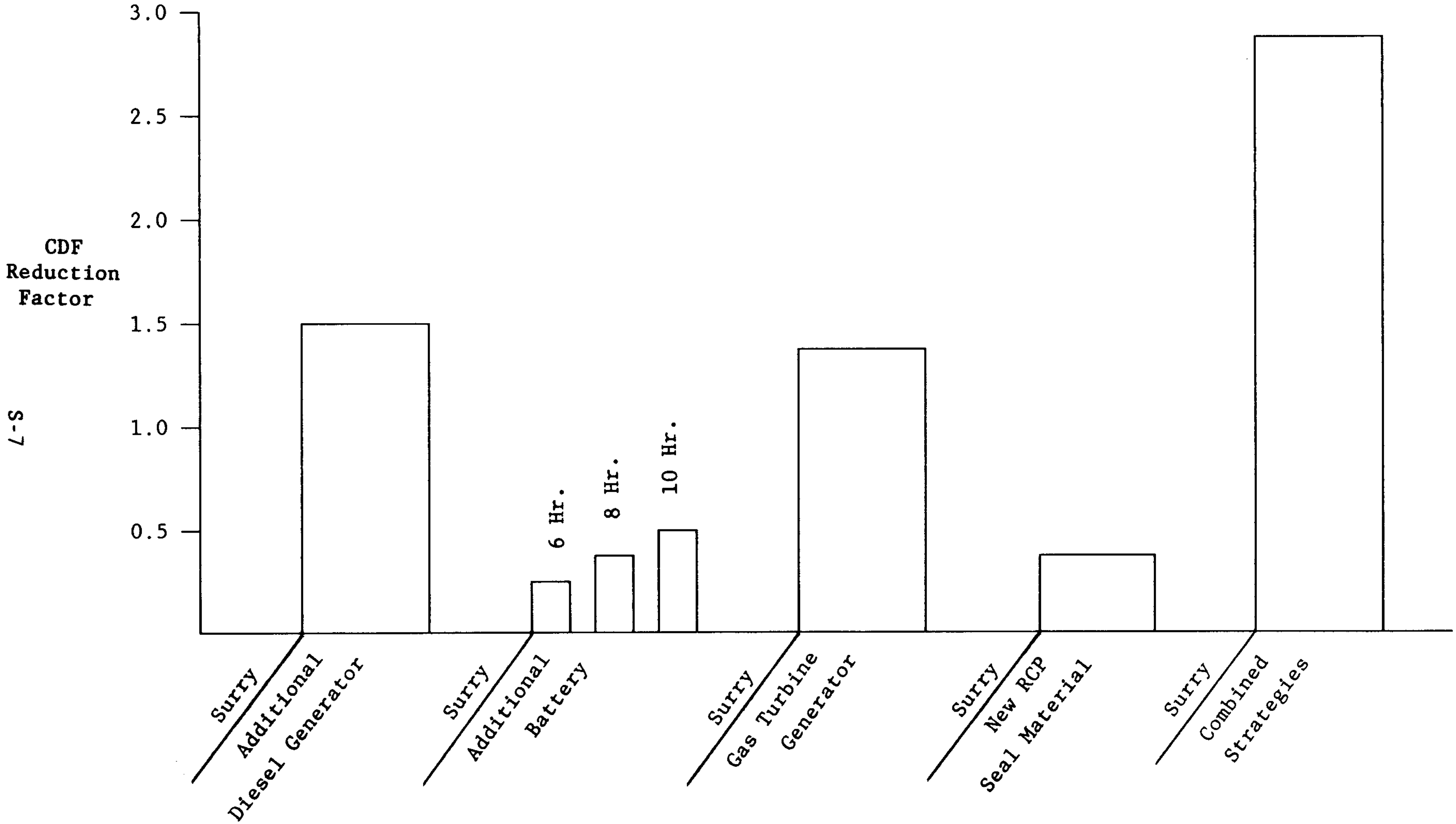

Figure S.2. Effect of Future Risk Management Strategies on the Core Damage Frequency

PRA information can assist the utilities and NRC in several parts of the emergency response decision-making process. The pre-accident evaluation process should involve a number of steps, including:

1. Characterization of possible source terms

2. Evaluation of site conditions, including population characteristics and road conditions

3. Evaluation of the operator's predictive capability

4. Identification of possible short-term emergency response actions

5. Identification of possible long-term emergency response actions

6. Integral evaluation of alternative strategies

The NUREG-1150 methods can assist in the evaluation of each step and support the development of site and accident-specific response strategies.

Phase 4 - Prevention of Vessel Breach

If core damage is inevitable or has already occurred, then the goal of risk management is to arrest the degradation process and retain the fission products and core materials within the vessel and reactor coolant system. Recovery may be attempted at any time from when the fuel rods are intact to when the corium is lying molten on the bottom of the reactor vessel. The options available are limited and generally would involve restoration of vessel water inventory and primary system heat removal. Currently, there are no detailed procedures related to the timing and injection of water into an overheated core. There is usually little or no guidance beyond instructions to flood the core if at all possible.

It is probably best to deal with situations in this phase of risk management in terms of plant states (collections of symptoms defining the plant status, e.g., pressure, temperature, and radiation levels) and functional responses. In evaluating various options using the NUREG-1150 methods, the following steps would be included:

1. Identify the risk important plant states

2. Identify the possible plant state variables (symptoms) that could identify these states

3. Determine the ability of the operators to use available instrumentation to identify existing plant states

4. Identify possible functional responses

5. Evaluate the probability and consequences of potential outcomes to each functional response

Once the evaluation is complete, then appropriate strategies can be selected and implemented. This implementation could involve procedures, guidance and hardware modifications along with modifications to training and plant practices.

The major goal of this phase is to obtain a coolable core and minimize radionuclide releases. A number of risk management strategies that could be proposed to achieve this goal include:

1. Addition of improved instrumentation

2. Use of non-safety systems to provide makeup water

3. Varying the rate and location of injection, depending on the particular plant state

4. Increasing or decreasing the primary system pressure, as appropriate for the scenario

Analyzing the possible outcomes of various actions is a complex process. Reflooding a degraded core can result in hydrogen generation, disruption of geometry and fuel coolant interactions. While no one advocates that a quench and recovery of the core should not be attempted, it is clear that there will be tradeoffs to consider when selecting the most appropriate method for recovering the core. The NUREG-1150 methods provide a framework for evaluating each possible recovery scenario from a probabilistic standpoint to identify potential outcomes and assess their influence on overall risk.

Phase 5 - Retention of Fission Products

If the primary system boundary is breached, then fuel and radionuclides will be released to the containment, and risk management will be oriented toward preserving containment integrity and/or strategies to reduce off-site radioactive releases. At this point, the risk management environment is changed in a number of important ways. First, the plant state characterization will rely more heavily on containment parameters, and the key diagnostic data are provided via different pathways. Second, different time scales may now govern the accident. Third, the systems and actions available for responding to the accident are largely different. Finally, the interface with off-site emergency response decisions is at its most critical stage.

The approach to this phase of risk management is similar to that for Phase 4 in that plant states and functional responses can form the basis for selecting risk management strategies. The five steps previously identified for Phase 4 are also utilized to develop risk management strategies for Phase 5.

Included in the identification of risk important plant states is the determination of available containment systems such as sprays, fan coolers, ignitors, venting and isolation systems, ice condensers, and suppression pools. Identifying containment status both before and after vessel breach is also important. Containment failure prior to vessel breach is possible in some scenarios, so conditions at the time of vessel breach must be identified. To determine the ability of operators to use available instrumentation to identify plant states, the analyst must consider the fact that equipment is not generally designed to operate in environments in which molten corium is present. Phenomena conditions in containment that must be considered include core-concrete interactions, direct containment heating, combustion, containment structural response, and fission product transport. For example, several relevant interactions that must be considered include:

1. Opening and closing a containment vent prior to vessel breach reduces the baseline containment pressure but accelerates the release of radionuclides

2. Flooding the reactor cavity may decrease the likelihood of core-concrete releases but also may accelerate the rate of pressure buildup due to increased steam production

3. With the containment at high pressure and high steam concentration, the actuation of sprays following power recovery will wash out suspended fission products but may de-inert the containment atmosphere, leading to hydrogen burns

A number of strategies may be considered to remove heat and retain fission products in this phase, including:

1. Addition of improved instrumentation

2. Management of combustible gases

3. Injection of water into containment

4. Venting strategies

5. Additional methods for containment heat removal

6. Additional methods for reducing suspended aerosols

7. Strategies for controlling high pressure melt ejection

Evaluation of Integrated Strategies

Up to this point, each risk management option has been evaluated separately. This gives a clear indication of the relative importance of each option in reducing core damage frequency or risk. A more likely approach involves the utilization of several risk management options together in an integrated strategy to increase the benefits to the plant. This combined effect of utilizing an integrated risk management strategy was examined at Surry. This strategy included the following options in combination:

- Addition of an independent diesel generator
- Use of an onsite gas turbine generator
- Extension of battery life
- Use of improved reactor coolant pump (RCP) seals

All of these options address station blackout sequences which account for two-thirds of the total Surry core damage frequency. To evaluate the combined effect of these options on the core damage frequency, plant models were changed to reflect each option. Each risk management strategy affects the core damage frequency less when evaluated in combination with other strategies than if evaluated separately. This is due to the fact that all of these strategies relate to station blackout sequences and overlap of mitigative coverage occurs (see the main report for more details). Figure S.2 includes the results of the integrated evaluation.

4. Evaluation of Current Risk Management Practices

The methods developed in NUREG-1150 can be utilized to evaluate the efficacy of current risk management strategies. Specific examples of risk management procedures currently incorporated at Surry and Peach Bottom and how they have reduced plant core damage frequency/risk are discussed in this section. The methods used to evaluate current strategies are straightforward. The CDF or risk is calculated with and without a particular procedure in place. However, in practice this can be a complex process, if removing an option changes the fundamental models in the PRA. This section concentrates on phase 1 and 2 options for Surry and Peach Bottom.

SURRY

Current Phase 2 Surry risk management options discussed in this section include the following, all of which were existing at the plant prior to the NUREG-1150 study:

1. Feed and bleed cooling

At Surry, like at most Westinghouse PWRs, feed and bleed cooling is utilized to restore heat removal from the core for accident scenarios in which all sources of feedwater to the steam generators is lost. The High Pressure Injection (HPI) system injects to the reactor vessel while the pressurizer relief valves allow discharge from the primary system to control the pressure.

2. Secondary blowdown

Under certain accident conditions it is necessary to perform a blowdown of the steam generators on the secondary side in order to depressurize and cool down the primary system. This allows low pressure systems to inject to the core. Most PWRs have some form of secondary blowdown procedure. However, all postulated sequences for which secondary blowdown is a necessary action become probabilistically insignificant (very low frequency) at Surry prior to the need for this action. At plants without cross connect injection capability and automatic switchover to recirculation, secondary blowdown could be much more important.

3. Auxiliary Feedwater (AFW) and HPI cross connect injection

In the event of a loss of HPI or AFW injection flow to Unit 1, Surry plant procedures direct the operator to recover by cross connecting to the analogous system at Unit 2. This procedure is specific to Surry.

PEACH BOTTOM

Significant risk management efforts at Peach Bottom examined in this section include:

1. Use of the Primary Containment Venting (PCV) system to prevent containment overpressurization

Operation of the Primary Containment Venting system as a Phase 2 and Phase 4 option prevents primary containment overpressurization and loss of certain core cooling functions during accident sequences in which all containment cooling is lost. Many Mark I and II BWR plants have procedures that are similar in principle, but the details vary widely from plant to plant.

2. Utilization of the High Pressure Service Water (HPSW) system as an alternate injection source

The HPSW system, as a Peach Bottom-specific Phase 2 option, is used as a backup source of coolant injection during a variety of accident sequences. Because most components are located outside containment and the suction source is a river, the HPSW system is largely independent of other safety systems, so dependent failures are not a factor.

3. An excellent diesel generator maintenance program

The emergency AC power system at Peach Bottom is very reliable largely because of excellent diesel generator maintenance practices which have reduced diesel generator failure rates by an order of magnitude. This is considered a Phase 1 risk management effort since it provides immediate mitigation of the loss of offsite power initiating event.

Figure S.3 shows the effect of the risk management strategies identified in this section on the CDF of the applicable plant. The reduction factor in the CDF attributable to each strategy is given, calculated by dividing the new CDF (without the strategy incorporated) by the current CDF. The strategy of secondary blowdown is not probabilistically important at Surry, although it provides a last resort means of primary system depressurization, given certain unlikely accident scenarios. Similarly, the diesel generator maintenance program at Peach Bottom is not probabilistically important, due to the importance of other failures that mask the diesel generator failures. These strategies could be important at other plants.

5. Evaluation of Direct PRA Benefits

Prior to the development of a specific risk management program, a PRA study can be useful in identifying vulnerabilities inherent in plant design and operation and can provide some direct risk management. A determination of the relative risk importance of problem areas at a plant, as determined by a PRA study, is useful to the utility in making changes to the plant. Examples of important plant and analysis changes that have occurred during the NUREG-1150 process are identified in this section. Some of these changes may have been influenced by findings in the NUREG-1150 analysis process, but they were all made with the intent to reduce risk and improve reliability.

<u>SURRY</u>

Recent modifications made at Surry include changes to the:

1. Uninterruptible Power Supplies

Uninterruptible power supplies that feed vital Instrumentation and Control busses were added to the electrical system. This change (Phase 1 of risk management) eliminated the loss of a 480 V bus as an initiating event.

2. Heat exchanger valves

The heat exchanger valves in the Containment Spray Recirculation system were replaced with more reliable valves which are tested more frequently. These Phase 2 changes lowered the mean value for common cause failure of the heat exchanger valves by a factor of 17, which significantly lowered sequence frequencies involving total loss of containment heat removal.

3. Power operated relief valve (PORV) and atmospheric dump valve (ADV) block valves

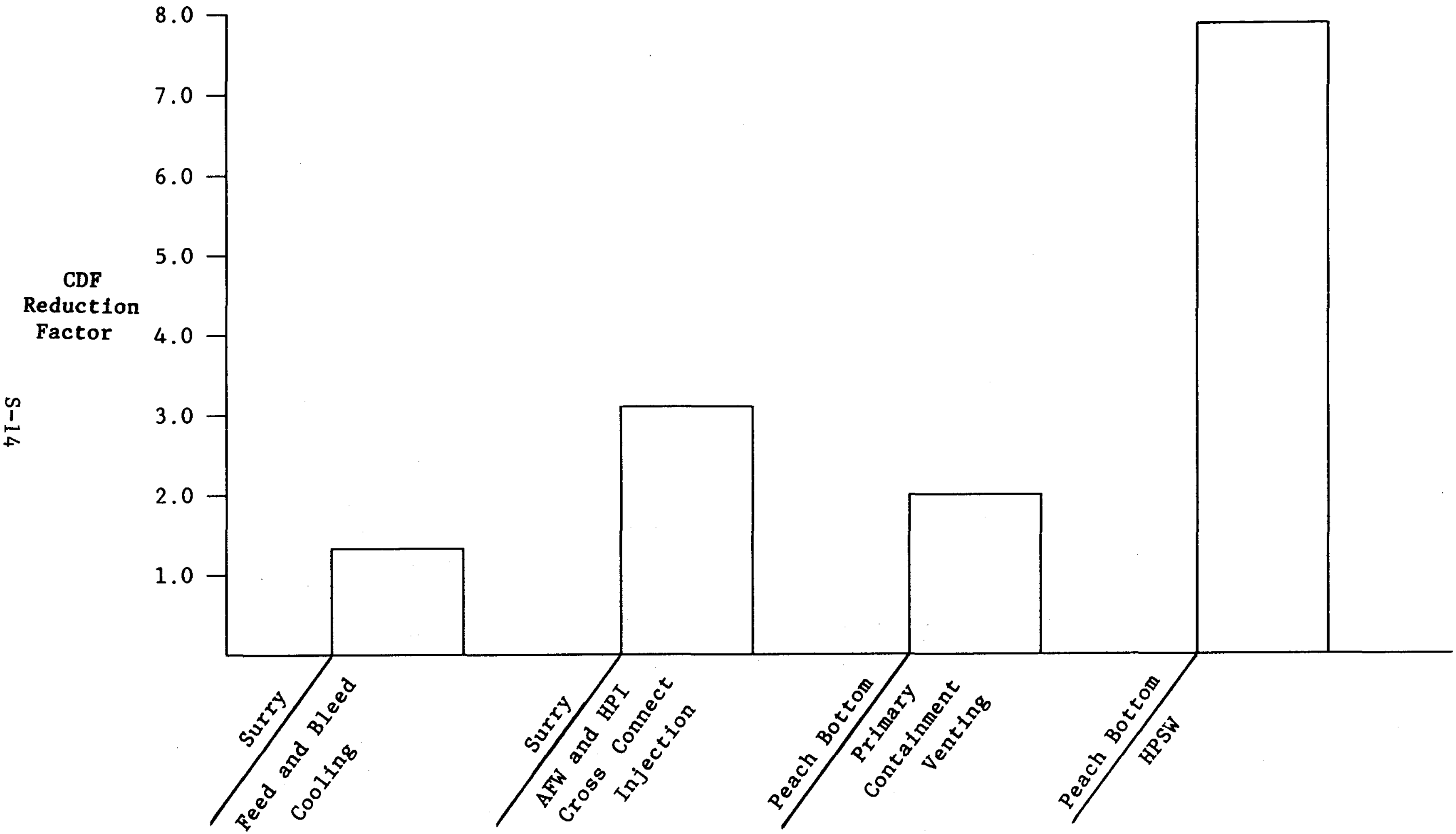

Figure S.3. Effect of Current Risk Management Strategies on the Core Damage Frequency

The accident responses of feed and bleed cooling and secondary blowdown require PORV and ADV operation, respectively. The Surry operations staff has been made aware of the importance of having the PORVs and ADVs available for accident mitigation, although no procedural or design changes were made. This heightened awareness is reflected in the NUREG-1150 analysis by increased probabilities for availability of the PORVs and ADVs, a Phase 2 risk management strategy.

PEACH BOTTOM

Several significant changes made at Peach Bottom include:

1. Changes to the Emergency Service Water (ESW) system

Phase 2 hardware and procedural changes have been made to the ESW system to ensure that ESW system blockage does not occur due to inadvertent closure of or maintenance on a critical valve.

2. Revised containment venting and station blackout (SBO) response procedures

Phase 2 and 5 containment venting procedures are still undergoing modification at Peach Bottom. Recent changes have affected the sequences in which venting will be attempted and the pressure at which it will begin. Station Blackout procedures have been revised to increase the expected battery life upon loss of all AC power.

3. Revised analysis of containment pressure capacity

The containment failure pressure used in the analysis was increased based on a revised analysis. This gives a more accurate representation of the likelihood of containment failure but does not significantly affect the sequence frequencies. However, accident progression results will be enhanced by a better representation of the plant response. Thus, both Phases 2 and 4 of risk management can be performed from a more accurate technical base.

SEQUOYAH

One significant Phase 2 change which has risk management implications was included in the Sequoyah analysis. In the draft NUREG-1150 analysis, charging and safety injection pumps were assessed to fail if operated without seal cooling from the Component Cooling Water (CCW) system. The plant supplied compelling evidence that the charging pumps do not require seal cooling, which eliminated from the analysis a sequence accounting for nearly one-third of the total plant core damage frequency (CDF).

GRAND GULF

Three recent Phase 2 modifications were incorporated at Grand Gulf including:

1. Modifications to the Firewater system

The plant has made significant hardware and procedural changes so that the Firewater system may be utilized as a last resort source of emergency coolant injection. This Phase 2 and 5 action has a significant impact on the core damage frequency.

2. New Emergency Operating Procedures

Updated emergency operating procedures were utilized in the final NUREG-1150 report, all of which assist the operator in accident diagnosis and mitigative actions.

3. A new assessment of the High Pressure Core Spray (HPCS) pump

The HPCS pump seals and bearings were assessed to catastrophically fail when pumping high temperature suppression pool water. Updated information on the HPCS pump seals and bearings was utilized to conclude that the seal failure will not be catastrophic, but will only result in leakage. Also, the bearings were assessed to withstand any expected harsh environment without failure. Due to these assessments, many sequences were eliminated from further consideration.

Figure S.4 shows the effect of the risk management strategies identified in this section on the CDF of the applicable plant. The reduction factor in the CDF attributable to each strategy is given, calculated by dividing the new CDF (without the strategy incorporated) by the current CDF. The strategies for which complete requantification was not possible or was not performed or estimated are given in Table S.1 with a qualitative summary of the effect of each on the plant CDF.

The combined effect of the strategies discussed in the three previous chapters could be examined for a particular plant. However, an in-depth analysis of combining strategies was not within the scope of this report. In many cases, different strategies for the same plant affect the same sequences, so that the combined effect is not additive.

6. Conclusions

This report presents a general approach for using PRA-type analyses to supplement risk management programs in all five of the identified phases. This approach is more detailed and comprehensive than previous approaches due to the advances in PRA technology as a result of NUREG-1150. This technology allows the in-depth, integrated treatment of all phases of severe accidents. Further, alternative outcomes in the progression of severe accidents can be explicitly treated.

PRA techniques have been demonstrated to be effective in addressing risk in three different ways:

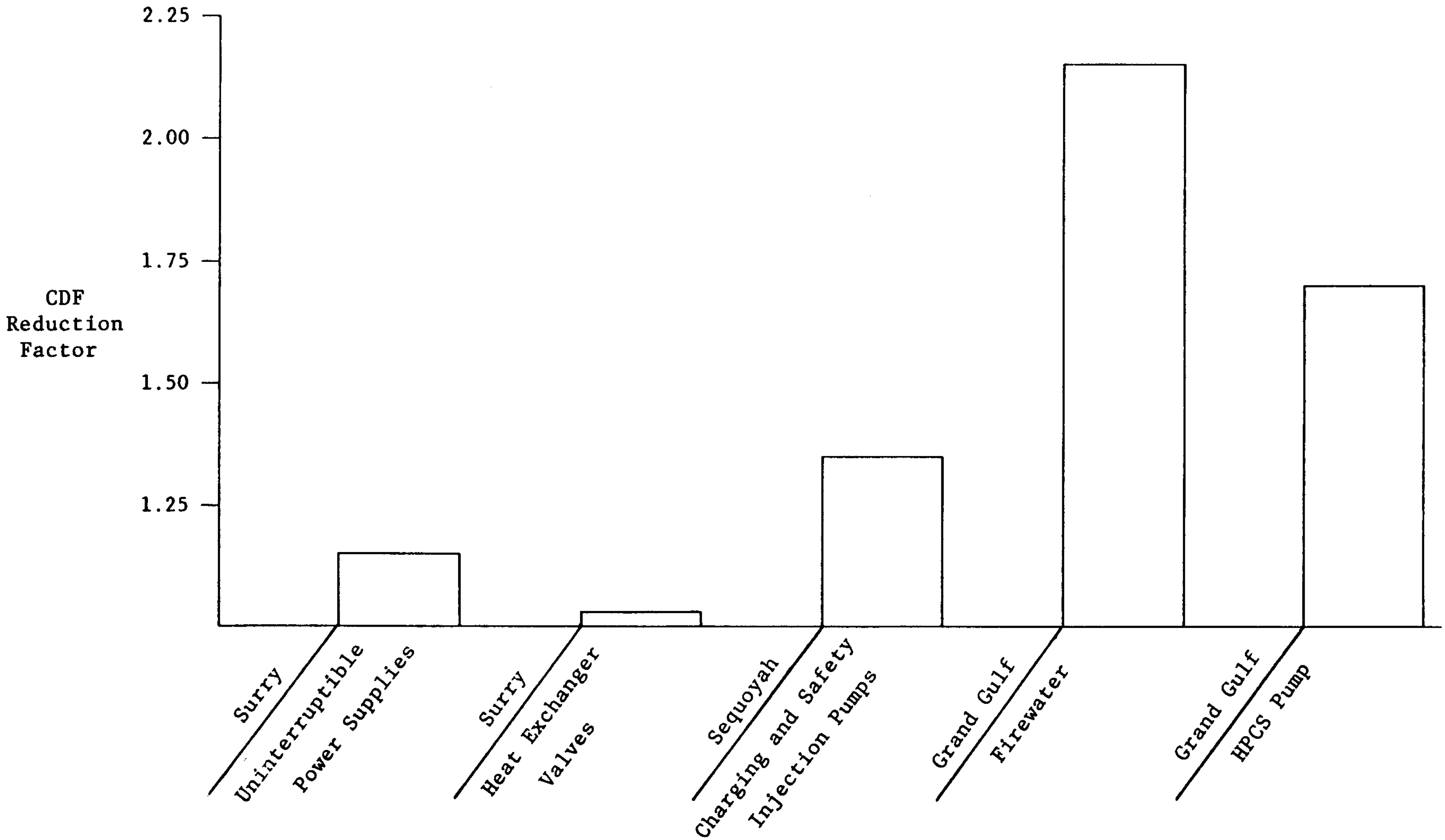

Figure S.4. Effect of Recent Plant Changes on the Core Damage Frequency

Table S-1

Qualitative Effect of Accident Management Strategies

Plant	Risk Management Strategy	Effect
Surry	Status of Block Valves	Increased plant staff awareness of importance of PORV and ADV availability; increased availabilities in plant models
Peach Bottom	Emergency Service Water System	Hardware and procedural modifications led to increased system reliability
Peach Bottom	Venting/Station Blackout Procedures	Changed the sequences impacted by containment venting; battery life increased during station blackout
Peach Bottom	Containment Pressure Capacity	More detailed and accurate understanding of containment failure results in enhanced backend representation
Grand Gulf	Emergency Operating Procedures	New procedures give operator increased capability for diagnosis and mitigative action

1. PRAs provide direct benefits by identifying plant vulnerabilities that are corrected by the utilities,

2. Current risk management procedures and hardware can be examined to determine their efficacy and help assure correct implementation.

3. Future risk management strategies can be developed and evaluated in an integrated fashion.

In fact, the nuclear industry has taken many positive steps to reduce risk since the accident at Three Mile Island. However, there are many improvements that are still possible. The capabilities identified and demonstrated in this report should become an integral part of future risk management analyses.

1. INTRODUCTION

1.1 Background

This report discusses the potential uses of NUREG-1150 and similar Probabilistic Risk Assessments (PRAs) in NRC and industry risk management programs. The methods and results produced in NUREG-1150 provide a framework within which current risk management strategies can be evaluated, and future risk management programs can be developed and assessed. PRAs have been used in the past for similar purposes, but the NUREG-1150 methods bring added depth and breadth to the process, along with a detailed explicit treatment of uncertainties. While the development of plant-specific risk management strategies is beyond the scope of this document, examples of the use of the NUREG-1150 framework for identifying and evaluating risk management options are presented. Thus, this work will support the current NRC risk management programs.

Risk management programs at nuclear power plants have two basic objectives:

1. Minimize the public health risk from nuclear power plants, and

2. Provide the capability for operators and decision-makers to effectively respond to and thereby reduce the frequency and consequences of severe accidents.

In practice, risk management can be divided into five separate, but interrelated, phases:

1. Prevention of accident initiators (reliability management),

2. Prevention of core damage (accident management),

3. Implementation of an effective emergency response (emergency response management),

4. Prevention of vessel breach and mitigation of radionuclide releases from the reactor coolant system (accident management),

5. Retention of fission products in the containment and other surrounding buildings (accident management).

"Accident Management" is a term that is often used in place of "risk management"; however, the former is usually applied to the late stages of phase 2 and phases 3 through 5. Thus, risk management is a more comprehensive approach.

A comprehensive PRA provides a framework for identifying severe accident vulnerabilities and analyzing current and future risk management options in an integrated fashion. The integrated analysis capability of PRA methods is crucial, because a particular action taken during one phase of the accident may significantly affect later phases. For example, a phase 2 option at a BWR might involve opening a containment vent. A PRA framework allows the evaluation of the impact of venting on future accident progression and can assist in the evaluation of evacuation strategies based on anticipated releases. In general, this report deals with the analysis of risk management options as part of the development of overall risk management strategies prior to an event. Future work could consider the benefits of having "on-line" PRA-based information, but that concept is not the focus of this report.

The nuclear industry has taken significant steps since Three Mile Island in the development of risk management strategies, particularly for phases 1 and 2. Industry trip reduction programs and improved emergency operating procedures are examples of industry initiatives that have reduced risk. However, there is still room for improvement in all phases, and particularly in phases 3 through 5. The development of comprehensive risk management strategies is an extremely complex process that requires further research by both NRC and industry. Such strategies involve development of a good understanding of severe accident phenomena and the response of equipment to resulting environments. The strategies must be sufficiently flexible that they can deal with the large uncertainties that remain associated with many of these phenomena.

1.2 Role of PRA in Risk Management

Severe reactor accidents involve extremely complex system and phenomenological responses that are often nonintuitive. When developing and evaluating risk management options it is important to understand how a particular action may affect other portions of the accident progression. The PRA methods developed for NUREG-1150 provide an integrated analysis framework that can evaluate the potential ramifications of a specific action over a wide range of possible outcomes. All five phases of risk management described above can be included in such an integrated analysis.

The actual PRA methods used in NUREG-1150 are described in References 2 and 3. The application of these methods to the evaluation of risk management strategies is summarized in Figure 1.1. All evaluations depend on an underlying technology base consisting of plant data, experiments, equipment tests, and computer models. This technology base supplies information to the integrated PRA framework so that realistic accident sequences and probabilities can be defined. All of the phases of risk management can then be considered, and options can be compared using various risk measures, including health and economic risk. Risk is not the only measure of the effectiveness of various risk management strategies. Cost and practicality of implementation are also important. However, a PRA framework with all of the enhancements of NUREG-1150 provides a powerful tool for supplementing current approaches.

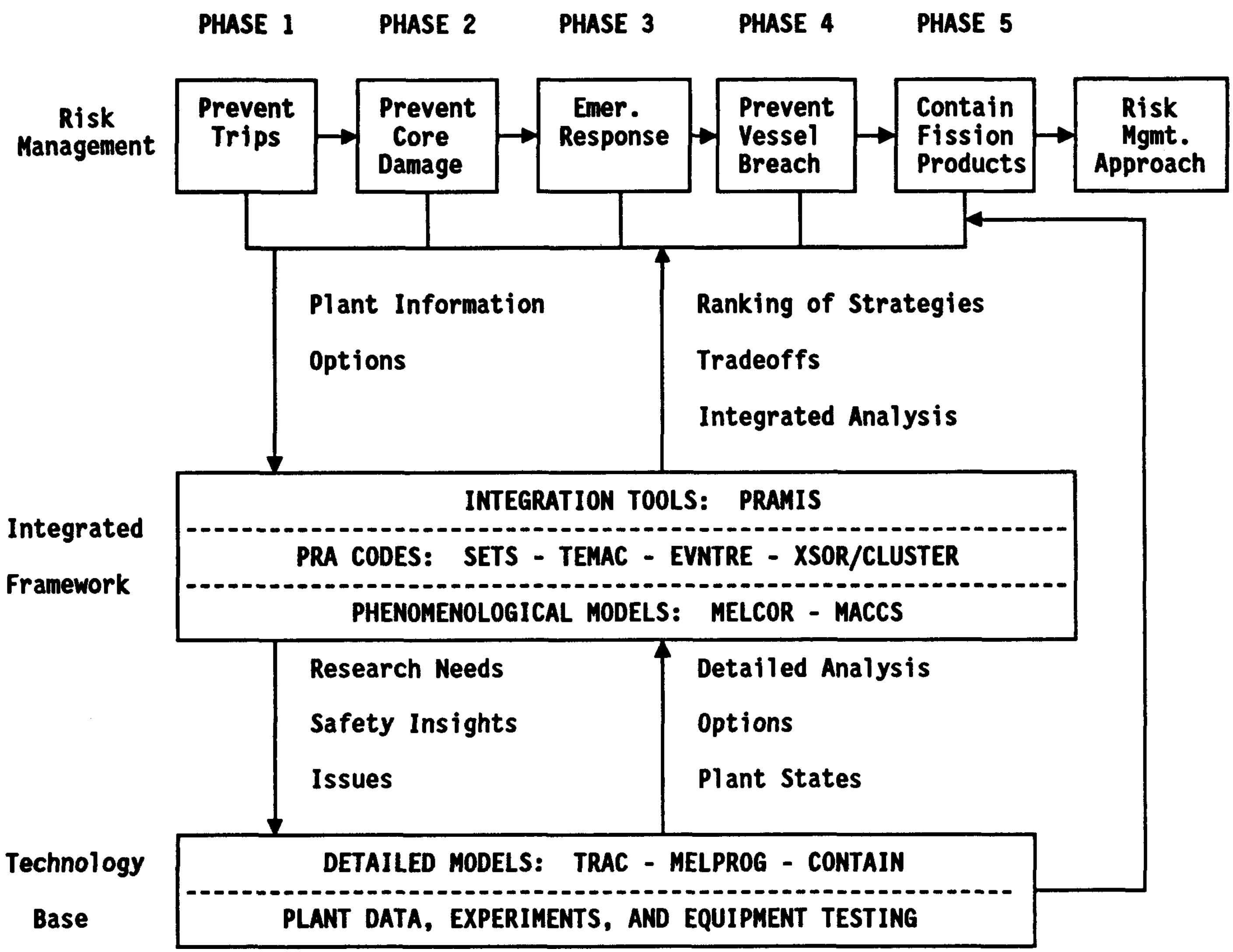

Figure 1.1. Risk Management Analysis Framework.

The actual evaluation of risk management options can be performed in a number of ways. The simplest evaluations deal with changes to the frequencies and probabilities within the probabilistic models. For example, changing out a valve for a more reliable model could be evaluated by simply changing the valve failure rate and recalculating the risk. Other changes involving changes to the plant configuration would require changing the underlying plant models (system fault trees, accident progression event trees, etc.) prior to recalculation. Note that it is possible that a change may eliminate some sequences and phenomena, but also may create new ones to consider. An example is the addition of a redundant and independent coolant injection system. Such a system would almost certainly be beneficial in an overall sense; however, the potential for an additional interfacing system LOCA would need to be considered. As another example, the addition of cross-ties between cooling systems at different units on the same site can increase the reliability of coolant injection, but at the same time produce possible flow diversion paths.

Perhaps the most significant area where PRA methods can contribute to risk management is in the treatment of uncertainties. The treatment of uncertainties in this report is limited but would be a major part of future studies. PRA results can supplement detailed deterministic calculations by identifying alternative outcomes for the important accident sequences. Using advanced probabilistic sampling techniques, multiple passes are made through the risk calculation, yielding a variety of possible risk measures along with their probabilities. By providing these possibilities, risk management can make the operators aware of the uncertainty in severe accident progression and the need for sufficient flexibility to deal with surprises that are likely to occur.

In the remainder of this report, the manner in which PRA methods can be applied to risk management is discussed. The Surry, Peach Bottom, Sequoyah, and Grand Gulf power plants are used as the reference plants for this effort. The scope of risk management options considered is limited to those that affect internally initiated events; however, the same approach is applicable to external initiators. Numerous qualitative examples are presented, along with some quantitative examples. The majority of the quantitative examples are for Surry, with a few important examples included for Peach Bottom and Grand Gulf. Numerous references are provided relating to the four plant studies. The reader will need to refer to these analyses in order to completely understand the examples. Chapter 2 briefly discusses the direct benefits to risk management that generally result from the performance of a PRA. Chapter 3 presents an evaluation of some of the current risk management strategies in place at the four plants. Chapter 4 discusses the uses of the NUREG-1150 tools to identify and evaluate future risk management options, and Chapter 5 presents the conclusions of the study.

2. EVALUATION OF FUTURE RISK MANAGEMENT STRATEGIES

This section addresses the use of NUREG-1150 methods in developing advanced risk management strategies. Some specific quantitative examples are presented later in the section following a discussion of the general approach.

2.1 Approach to the Development of Risk Management Strategies

As discussed in Chapter 1, the methodology discussed in this report is intended to address the following five interrelated phases of risk management:

Phase 1. Prevention of accident initiators,

Phase 2. Prevention of core damage,

Phase 3. Implementation of effective emergency response,

Phase 4. Prevention of vessel breach and mitigation of radionuclide releases from the reactor coolant system, and

Phase 5. Retention of fission products in the containment and other surrounding buildings.

An integrated and flexible approach to risk management is needed because:

1. There are many interrelationships and dependencies among the five phases of risk management, and

2. There is significant uncertainty in the system and phenomenological responses during a particular severe accident.

An integrated Level 3 PRA capability allows the treatment of the interrelationships and dependencies among the different phases. System and phenomenological models are constructed during the course of a PRA reflecting the characteristics of a particular risk management strategy, and a selected risk calculation is performed. By developing the models probabilistically, alternative outcomes can be identified that reflect the uncertainty in system and phenomenological responses. From the standpoint of the plant configuration and system design, these evaluations of postulated accident scenarios are relatively straightforward. The implementation of risk management strategies in the form of procedures, however, is more complex. Of particular concern is the development of procedures that are sufficiently flexible to deal with uncertainties. Fortunately, this is an area where the nuclear industry has already made considerable progress.

The uncertainties in accident progression clearly indicate the need for symptom and functional oriented procedures, rather than event based procedures. The industry has moved rapidly in that direction since TMI, including the development of advanced control room displays. The current procedures in place at most plants are generally very good with respect to the first two phases of risk management. It is the late phases of a severe accident that needs more attention and development.

Current symptom-based procedures can potentially be extended into the late phases of severe accidents. Along with system status, however, the reactor coolant system and containment status must be considered, resulting in an overall plant state. A representative approach for dealing with plant states is illustrated in Figure 2.1. As shown in the figure, the operator considers a number of indicators (symptoms), including those for system status, system pressure and radiation levels, in order to classify the current plant state. A number of actions may be possible for each plant state, depending upon the symptoms of a given plant state. Based on prior analysis, including an assessment of risk implications, to provide guidance for the operator, a particular action would be selected. This frees the operator from having to identify the event prior to initiating mitigative action, as is the case for event-based procedures. The outcome of the action is then assessed in the form of parameter changes (temperature, pressure, etc.), which forms the basis for any subsequent action. For severe accidents there may be significant uncertainty regarding the outcome of any particular action, e.g., reflooding a molten core in the reactor cavity. Thus, monitoring of the outcome of actions is important. In other words, the plant state will continue to evolve until the accident is terminated by achieving both subcriticality and stable, long-term decay heat removal. By performing prior analyses with PRA and other tools, the possible outcomes to operator accident response can be identified and the plant personnel are more likely to recognize unusual events when they occur.

It should be obvious from the above discussion that a key element in managing severe accidents is the availability of reliable monitoring instruments and displays. In developing current risk management plans, it should be recognized that much of the available instrumentation is not designed to operate in the severe pressure, temperature, and radiation environments that may occur in the risk-dominant accident sequences.

With the above discussion in mind, each of the five phases of risk management will be examined below, with regard to potential future improvements.

2.2 Phase 1 - Prevention of Accident Initiators

PRA tools are extremely useful in identifying important accident initiators and evaluating methods for reducing their effect on the core

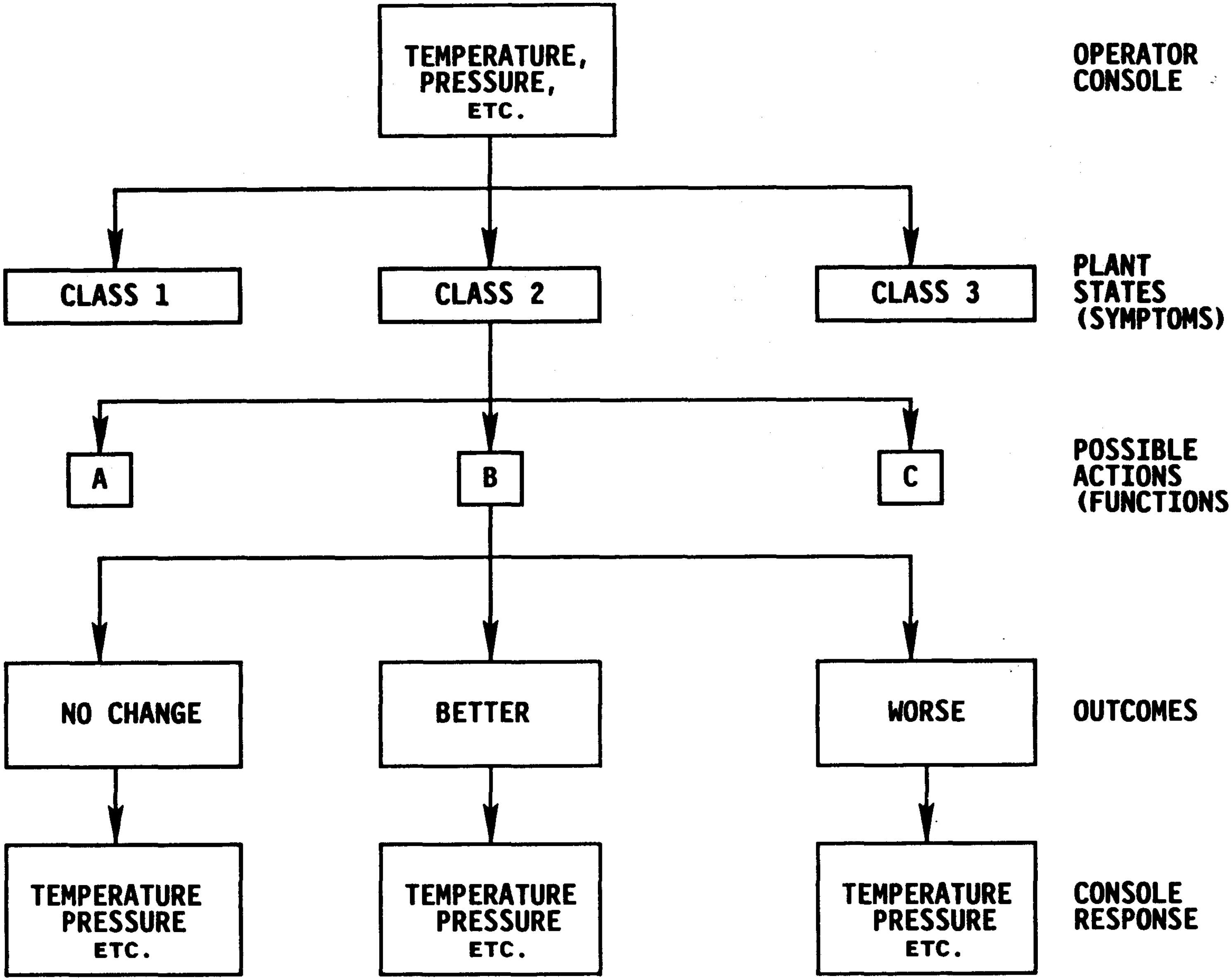

Figure 2.1. Use of Plant States in Risk Management.

damage frequency and risk. The accident initiators considered here are generally those that occur from full power, thus requiring a plant trip and the response of safety systems for decay heat removal. It is important to note, however, that significant accidents may also occur from low power or even shutdown conditions.

Industry trip reduction programs have already had an impact in this area. However, PRA tools can identify and evaluate areas for future improvements. For discussion purposes we will include in this phase both actions that occur prior to the initiator, and those actions that could occur within the first few minutes after the initiator to terminate the event.

The first step in reducing the impact of accident initiators is to identify the initiators that are important to risk. This is a straightforward process with the availability of a PRA. Both the initiators dominating the core damage frequency (CDF) and those dominating the health and economic risk can be readily identified. This information is easily obtained in NUREG-1150 and supporting documentation for NUREG-1150 plants (NUREG/CR-4550 and NUREG/CR-4551 volumes).

It is extremely important to recognize that the initiators most significant to risk are not usually those that are the most frequent. Initiating events such as loss of offsite power, interfacing loss of coolant accidents (LOCAs), and anticipated transient without scram (ATWS) are likely to be more important than simple turbine trips. Thus, trip reduction plans that merely reduce the total number of trips may not significantly reduce plant risk.

Given that the most important initiators are identified, the next step is to ascertain the root causes of those failures. For example, transient initiators, such as loss of feedwater or turbine trip, can occur due to many different causes. Before the frequency of such events can be reduced, the reasons for their occurrence must be understood. Sometimes this information can be obtained from a PRA, but often more studies of plant data and operating and maintenance practices are needed.

Once the initiators are identified and understood, they can be prioritized in terms of the resources needed to reduce their importance. The risk importance of a particular initiator can be readily obtained from the PRA; however, upon examination of the root causes, it may be determined that reduction of that initiator is not practical. This is particularly true in cases where no single root cause dominates the frequency of the selected initiator.

The next step is to identify options for reducing the frequency of important initiators. These options can include:

1. Improvements to operating procedures
2. Improvements to test and maintenance procedures
3. Changes to technical specifications and limiting conditions for operation

4. Changes to hardware and system configurations
5. Adding or revising automatic "early time" responses

The selection of specific options depends upon the root causes of the important initiators.

The final step in this process is to evaluate the risk reduction of each option using the PRA framework. Options can be evaluated in terms of their impact on the core damage frequency and/or overall risk. In the section below, a future option for the Surry plant is discussed. The risk management options discussed in this section and subsequent sections are not necessary plant changes, but rather are examples of how PRA techniques can be used to identify and evaluate risk management options.

2.2.1 Additional Diesel Generator at Surry

The core damage frequency in the revised NUREG/CR-4550 Surry Unit 1 report [4] is dominated by the contribution from station blackout (SBO) sequences. Four groups of station blackout sequences are dominant in the Surry analysis. These include stuck-open relief valve (SBOQ), loss of auxiliary feedwater (SBOL), reactor pump seal LOCA (SBOS), and battery depletion (SBOB) sequences. Table 2.1 shows SBO sequence subgroups, their mean core damage frequencies, and the percentages of the total Surry CDF.

Approximately two-thirds of the total CDF is due to SBO sequence contributions. Strategies to reduce the frequency of SBO sequences would significantly affect the total plant CDF and risk.

Table 2.1

Surry Station Blackout Sequence Subgroups

Sequence Subgroup	CDF	% of Total
SBO - Batt. Depl. (SBOB)	1.14E-5	27.2
SBO - Seal LOCA (SBOS)	8.60E-6	20.5
SBO - AFW Failure (SBOL)	6.00E-6	14.2
SBO - Stuck-Open PORV (SBOQ)	2.50E-6	6.0
Total SBO Contribution	2.85E-5	67.9

Among the dominant contributors to the SBO frequency at Surry are various failures of the diesel generators, including common cause failures. Surry has one diesel generator dedicated to each unit plus a third diesel generator that is shared between the two units. One strategy to mitigate Unit 1 SBO scenarios is to add an independent diesel generator dedicated to that unit, while keeping the swing diesel shared between the two units. The addition of a diesel would not directly prevent the initiator which is a loss of off-site power, but would provide mitigation within a few minutes and could thus be considered a Phase 1 risk management alternative. The added diesel generator should be from a different manufacturer, be self cooled, have an independent DC power supply, and be housed at a separate on-site location. Common cause coupling to the existing diesel generators could then be neglected for most accidents.

The effect of an additional diesel generator at Unit 1 can be quantified by performing a recovery action on the SBO sequences. Two basic events were created to represent failure to restore emergency AC power using the new diesel generator. These events, OEP-DGN-RE-DGST and OEP-DGN-RE-DGLT, are applicable to short term sequences and long term sequences, respectively, and are inclusive of all types of diesel generator unavailability. For this analysis, the new diesel generator is assumed to have the same independent failure rates as the existing diesel generators.

Discussions with the Surry analysis team leader resulted in values for mean DG unavailability for long term and short term sequences of 0.04 and 0.03, respectively. The probability for long term unavailability (0.04) comes from the sum of the probabilities of failure to start (2.2E-2), test and maintenance unavailability (6E-3) and failure to run for six hours (1.2E-2). The probability for short term unavailability (0.03) comes from the sum of the probabilities of failure to start (2.2E-2), test and maintenance unavailability (6E-3) and failure to run for two hours (2E-3). Recovery with the two new basic events was applied to 1492 cut sets in eight intermediate plant damage states (PDSs).*

Quantification using the Top Event Matrix Analysis Code (TEMAC) was performed on the individual plant damage states affected by the inclusion of a new diesel generator. The resulting point estimate of core damage frequency was found to be 1.71E-5. Thus, the CDF is reduced by about a factor of two, and the total SBO contribution is reduced from 67.9% to 30.4%. The results for the intermediate PDSs, primary PDSs, and total plant CDF are given in Tables 2.2 and 2.3.

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* Intermediate and primary plant damage states are defined in Reference 4.

Table 2.2

Changes to Intermediate PDSs Due to Additional Diesel Generator

Intermediate Plant Damage State	SBO Type	Existing CDF	New CDF
S2RRR-RCR	SBOQ	1.67E-6	4.28E-7
S2RRR-RDR	SBOQ	6.03E-7	1.47E-7
S3RRR-RCR	SBOS	2.41E-7	4.20E-8
S3RRR-RDR	SBOS	6.21E-6	1.17E-6
TRRR-RCR	SBOB	1.72E-8	7.22E-10
TRRR-RDR	SBOB	7.09E-7	1.42E-7
TRRR-RDY	SBOB	7.17E-6	1.72E-6
TRRR-RSR	SBOL	4.60E-6	1.57E-6
Total SBO Frequency		2.12E-5	5.20E-6
Total Core Damage Frequency		3.30E-5	1.71E-5

Table 2.3

Changes to Primary PDSs Due to Additional Diesel Generator

PDS	Existing CDF	New CDF
PDS1 - Slow Blackout	1.68E-5	3.63E-6
PDS2 - Fast Blackout	4.60E-6	1.57E-6

2.3 Phase 2 - Prevention of Core Damage

The occurrence of an initiating event leads to challenges to the plant safety systems. For full power events, the operators must bring the plant to a subcritical condition with adequate water inventory and decay heat removal. As indicated earlier, the nuclear industry has made significant advancements in this area by developing symptom-based procedures. For example, at many BWRs the procedures are based on responding to four critical parameters:

1. Reactor power,
2. Containment pressure,
3. Reactor vessel level, and
4. Reactor pressure.

This approach eliminates the need to precisely identify the particular accident sequence that is in progress. However, even with this approach, there are uncertainties regarding the phenomenology of particular accidents and the response of control room instruments to certain off-normal events. For example, there has never been a sustained ATWS event at a significant power level. For this case, the thermal-hydraulic response is very uncertain, although a precise response is usually hard-wired into simulators and assumed in developing specific emergency procedures.

Further, the response to a particular event is likely to involve the use of systems that are tested frequently, but that are rarely used in actual operation. Once the event has started, the operators may see control room indications that they have never encountered before. Thus, the quality of both the hardware and operator training is important.

From an analysis standpoint, the evaluation of phase 2 options is similar to the evaluation of phase 1 options. The first step is to identify important accident sequences. For these sequences, the PRA importance calculations identify those failures that contribute most to the core damage frequency. To the extent possible, the root causes of these failures should be identified. Based on this evaluation, enhanced risk management options can be proposed. These could include:

1. Improvements to operating procedures
2. Improved operator training and staffing
3. Improved test and maintenance procedures for safety-related systems
4. Hardware modifications

Some of these methods are the same ones identified for prevention of accident initiators; however, here we are concentrating on the systems that must respond to an initiating event, not the ones that caused the event.

As discussed earlier, the dominant sequences at the Surry plant from a frequency standpoint are those involving station blackout. Among the significant contributors to the core damage frequency are: 1) failure to recover offsite power prior to battery depletion, 2) failure of the diesel generators, and 3) an induced reactor coolant pump seal LOCA. Using the NUREG-1150 methodology, three options are evaluated below that address these particular failures.

2.3.1 Extended Battery Life

As noted previously, the dominant contribution to the Surry core damage frequency is from station blackout sequences that include subsequent battery depletion. Approximately 27 percent of the total Surry CDF is from sequences with station blackout followed by battery depletion. These sequences are grouped into the three intermediate plant damage states described below:

1. TRRR-RCR - Battery depletion, steam generators (SGs) not depressurized, no RCP seal cooling

2. TRRR-RDR - Battery depletion, SGs depressurized, no RCP seal cooling

3. TRRR-RDY - Battery depletion, SGs depressurized, RCP seal cooling operating

One Phase 2 risk management option to reduce the CDF is increased battery life which allows more time for operator recovery actions during the first few hours following an initiator. Two changes could be incorporated at the plant to extend battery life; 1) increased DC load shedding, and 2) installing new battery(s). Associated increases in fail-to-run probabilities for the AFW motor-driven pumps (due to longer mission time) must accompany increases in battery life.

As currently modeled, the mean time to failure for the batteries at Surry is four hours. Including the postulated three hours to arrive at core uncovery following battery failure, a time of seven hours is used in the NUREG-1150 analysis for nonrecovery of AC power (NRAC-7HR). The assigned probability of not recovering power in seven hours (NRAC-7HR) is 0.05. Considering the potential for implementing one or more of the three strategies identified above, three increased battery depletion times were chosen. For each of these times, new NRAC probabilities were taken from Surry-specific AC power recovery estimates. Probabilities for the corresponding AFW pump fail-to-run events were accordingly changed. The current battery life as modeled in the Surry report was increased by 50%, 100%, and 150%, as were the associated AFW pump events. An assumption was made that, for longer battery life, the three hour time to subsequent core damage would be extended to four hours as a result of decreased decay heat loads and a generally more stable situation. The three new values for NRAC time are then 10, 12, and 14 hours, respectively. Table 2.4 shows the chosen NRAC times, AFW pump fail-to-run events, and associated probabilities. Quantification with TEMAC was performed using these probabilities for three new cases corresponding to the three new NRAC times.

Point estimates of the core damage frequency for the intermediate and primary plant damage states are given in Table 2.5. As shown, the frequencies of the three intermediate plant damage states are reduced by factors of two to four, depending on the battery life selected. However, the total core damage frequency is reduced by less than a factor of two.

Table 2.4

Battery Depletion Data

Battery Depletion (Hrs)	NRAC (Hrs)	NRAC Probability	AFW Fail-To-Run Basic Event	AFW Fail-To-Run Probability
4	7	0.0500	AFW-MDP-FR-3A1HR	3.0E-5
			AFW-MDP-FR-3A24HR	7.2E-4
			AFW-MDP-FR-3A6HR	1.8E-4
			AFW-MDP-FR-3B1HR	3.0E-5
			AFW-MDP-FR-3B24HR	7.2E-4
			AFW-MDP-FR-3B6HR	1.8E-4
6	10	0.0260	AFW-MDP-FR-3A1HR	4.5E-5
			AFW-MDP-FR-3A24HR	1.1E-3
			AFW-MDP-FR-3A6HR	2.7E-4
			AFW-MDP-FR-3B1HR	4.5E-5
			AFW-MDP-FR-3B24HR	1.1E-3
			AFW-MDP-FR-3B6HR	2.7E-4
8	12	0.0185	AFW-MDP-FR-3A1HR	6.0E-5
			AFW-MDP-FR-3A24HR	1.4E-3
			AFW-MDP-FR-3A6HR	3.6E-4
			AFW-MDP-FR-3B1HR	6.0E-5
			AFW-MDP-FR-3B24HR	1.4E-3
			AFW-MDP-FR-3B6HR	3.6E-4
10	14	0.0146	AFW-MDP-FR-3A1HR	7.5E-5
			AFW-MDP-FR-3A24HR	1.8E-3
			AFW-MDP-FR-3A6HR	4.5E-4
			AFW-MDP-FR-3B1HR	7.5E-5
			AFW-MDP-FR-3B24HR	1.8E-3
			AFW-MDP-FR-3B6HR	4.5E-4

Table 2.5

Changes in CDF for SBO-Batt Plant Damage States Due to Increased Battery Life

NRAC Time (Hrs)	Intermediate Plant Damage State	Existing CDF	New CDF
10	TRRR-RCR	1.72E-8	8.94E-9
	TRRR-RDR	7.09E-7	3.96E-7
	TRRR-RDY	7.17E-6	3.73E-6
PDS1 - Slow Blackout		1.68E-5	1.30E-5
Total Core Damage Frequency		3.30E-5	3.03E-5
12	TRRR-RCR	1.72E-8	6.36E-9
	TRRR-RDR	7.09E-7	2.62E-7
	TRRR-RDY	7.17E-6	2.65E-6
PDS1 - Slow Blackout		1.68E-5	1.18E-5
Total Core Damage Frequency		3.30E-5	2.91E-5
14	TRRR-RCR	1.72E-8	4.81E-9
	TRRR-RDR	7.09E-7	1.99E-7
	TRRR-RDY	7.17E-6	2.01E-6
PDS1 - Slow Blackout		1.68E-5	1.11E-5
Total Core Damage Frequency		3.30E-5	2.84E-5

2.3.2 Use of a Gas Turbine Generator

Current NUREG-1150 modeling and analysis of the Surry plant have not included the use of the on-site gas turbine generators for recovery of station blackout sequences. Two gas turbine generators (16 MW and 25 MW) are available to provide emergency AC power to safety and non-safety related equipment. The gas turbine generators were not included in the base case analysis because, under current administrative control and with the current system configuration, it is not clear if they could be made operable prior to core damage in the station blackout sequences of interest.

In order to give credit for the addition of one gas turbine generator for emergency AC power, it is assumed that Surry plant personnel have the authority to start the gas turbines when demanded and that one hour is required to start the gas turbines and energize the safety buses. This procedure is treated as a recovery action with no changes to the system fault trees. Previously in Section 2.2.1, the addition of a diesel generator was treated as a Phase 1 option, because the diesel generator could be started almost immediately. Since the gas turbine generators do not prevent the accident initiator and do not lead to immediate accident mitigation, these actions are more appropriately included in Phase 2.

As noted in previous sections, there are four groups of station blackout sequences to consider. Using the one-hour assumption to start the gas turbines, only the SBOS (reactor pump seal LOCA with 4.5 hours non-recovery time) and SBOB (battery depletion with 7 hours non-recovery time) groups can be recovered. These groups include the following five intermediate plant damage states:

1. S3RRR-RCR - Seal LOCA, SGs not depressurized, no RCP seal cooling

2. S3RRR-RDR - Seal LOCA, SGs depressurized, no RCP seal cooling

3. TRRR-RCR - Battery depletion, SGs not depressurized, no RCP seal cooling

4. TRRR-RDR - Battery depletion, SGs depressurized, no RCP seal cooling

5. TRRR-RDY - Battery depletion, SGs depressurized, RCP seal cooling operating

All intermediate PDSs above fall into the primary plant damage state grouping PDS1 (slow station blackout sequences).

A new basic event was created, OEP-GTG-RE-GTG1, to represent failure to restore emergency AC power with a gas turbine generator. This basic event is inclusive of all types of gas turbine unavailability (failure to start, failure to run, out for maintenance or repair, and failure to restore after maintenance or repair) and was given a mean unavailability of 0.1. The value of 0.1 came from discussions with the Surry analysis team leader and his assessment of the various contributions to unavailability. Recovery with this basic event was applied to 2034 cut sets in the five plant damage states.

Requantification was performed for the individual plant damage states affected by the gas turbine generator recovery. The frequency of each plant damage state was reduced by a factor of 10 (effectively, every cut set in these plant damage states was multiplied by 0.1). The resulting point estimate of the total core damage frequency was found to be 2.05E-

5, which is about a 40% reduction from the original point estimate of 3.30E-5. The results for the individual plant damage states and the total CDF are summarized in Table 2.6.

Table 2.6

Changes to Surry Plant Damage States
Due to Use of a Gas Turbine Generator

Intermediate Plant Damage State	Type	Existing CDF	New CDF
S3RRR-RCR	SBOS	2.41E-7	2.41E-8
S3RRR-RDR	SBOS	6.21E-6	6.21E-7
TRRR-RCR	SBOB	1.72E-8	1.72E-9
TRRR-RDR	SBOB	7.09E-7	7.09E-8
TRRR-RDY	SBOB	7.17E-6	7.17E-7
PDS1 - Slow Blackout		2.68E-5	3.84E-6
Total Core Damage Frequency		3.30E-5	2.05E-5

2.3.3 New Reactor Coolant Pump Seals

The NUREG-1150 analysis for Surry uses a model to predict the performance of the reactor coolant pump seals during transients in which seal cooling is lost. Resulting higher seal temperatures can lead to degradation. Critical to the performance of the reactor coolant pump seals are elastomer O-rings, which lose their sealing ability and may extrude at temperatures substantially higher than that of seal cooling water under normal conditions. LOCAs at a wide range of coolant leak rates can result from such postulated seal failures.

Reactor coolant pump seal failure at Surry is most important during station blackout sequences. In particular, the SBOS and SBOB sequence groups are affected. These sequence groups include four intermediate plant damage states described previously; S3RRR-RCR, S3RRR-RDR, TRRR-RCR, TRRR-RDR.

The issue of reactor coolant pump seal failure was included in the NUREG-1150 expert elicitation process [5]. To predict the performance of these pump seals under accident conditions, probabilities for various leak rates were elicited for the existing O-ring material and for an improved O-ring material. Installation of improved seal O-rings would be a Phase 2 risk reduction strategy. The prominent difference between existing and new seal material is the predicted time-dependent performance. A leak rate for the existing O-rings may not remain constant within a postulated leakage scenario. The probability of being at a certain leak rate can depend upon how long the pump seals have been exposed to a loss of cooling, since it is probable that certain leak rates degrade into higher leak rates with time. However, according to the expert elicitation results, the performance of the new O-ring material is not expected to vary substantially over the time intervals of interest. Leak rate probabilities for the new O-ring material reflect this expected improvement in performance.

The pump seal LOCA model for Surry consists of eight seal success and failure states representing all three pumps combined. These states include one state with the design leak rate of 63 gpm and seven states of various accident leak rates ranging from 183 to 1440 gpm. Each leak rate has associated with it at least one calculated length of time elapsed between the loss of RCP seal cooling and the start of seal leakage. Recovery of RCP seal cooling within this time frame will prevent the accident leakage.

The eight basic events are identified in Table 2.7. Each basic event name contains in it a leak rate (gpm) and an associated length of time (minutes). The event of no seal LOCA has the basic event name, NSLOCA, and represents the occurrence of leakage at the cumulative design leak rate of the three pumps (21 gpm per pump). Three basic events represent the leak rate of 183 gpm, each with a different time for recovery of RCP seal cooling. This difference in times is due to the belief that for pump seals with the existing O-ring material, the leak rate of 183 gpm may commence at difference times following loss of seal cooling, depending upon the conditions of a particular accident pathway. Two basic events represent the evolution of a lesser leak rate to a higher leak rate (467 and 561 gpm). The leak rates from new RCP seals are expected to remain nearly constant for the duration of the seal LOCA event.

Mean probabilities for the eight basic events representing the various seal leak rates for the existing O-ring material were replaced with probabilities reflecting expert judgment on the performance of the new O-ring material. Predicted seal leak rates for the new O-ring material of approximately the same magnitude as seal leak rates for the existing material were matched and new leak rate probabilities were substituted for the existing leak rate probabilities. In some cases it was necessary to lump together new leak rates of similar magnitude that closely

Table 2.7

Seal LOCA Leak Rates and Probabilities

Basic Event Name	Existing Leak Rate (gpm)	Existing Probability	New Leak Rate (gpm)	New Probability
NSLOCA	63	2.70E-1	63	8.11E-1
RCP-LOCA-183-90	183	1.40E-2	103/183/224	2.67E-2
RCP-LOCA-183-150	183	1.61E-2	0	0
RCP-LOCA-183-210	183	1.61E-2	0	0
RCP-LOCA-467-150	467	1.27E-1	294/372/425	9.80E-3
RCP-LOCA-561-150	561	4.00E-3	516/526/546	1.45E-1
RCP-LOCA-750-90	750	5.30E-1	602/614/750	8.17E-3
RCP-LOCA-1440-90	1440	4.30E-3	1440	5.00E-3

correspond to an existing leak rate. This matching of existing and new leak rates allows quantification to be performed without recalculating the AC power non-recovery times, since the leak rates are similar in magnitude. The basic events, existing and new leak rates, and associated probabilities are shown in Table 2.7.

Requantification using TEMAC was performed for the appropriate Surry intermediate plant damage states using the new leak rate probabilities for the seal LOCA basic events, assuming that the new O-ring material was in place. All intermediate PDSs fall into the slow blackout plant damage state PDS1. The results for the intermediate PDSs, primary PDS, and total plant CDF are summarized in Table 2.8. As a result of using the new material, the frequency of the SBOS scenarios is reduced substantially. However, it is interesting to note that the SBOB scenarios are actually increased in frequency. This occurs because some sequences that previously were a result of a seal LOCA now progress to battery depletion sequences. This example illustrates the need to perform risk management analyses systematically in order to fully understand the implications of selected actions. The resulting point estimate of the total core damage frequency is found to be 3.00E-5, while the original point estimate is 3.30E-5. Thus, even though the SBOB sequences are increased, the overall effect is a small reduction in the CDF.

Table 2.8

Changes to Core Damage Frequencies
Due to Improved O-Ring Material

Intermediate PDS	Type	Existing CDF	New CDF
S3RRR-RCR	SBOS	2.41E-7	5.80E-8
S3RRR-RDR	SBOS	2.61E-6	1.53E-7
TRRR-RCR	SBOB	1.72E-8	5.16E-8
TRRR-RDR	SBOB	7.09E-7	2.13E-6
PDS1 - Slow Blackout		1.68E-5	1.56E-5
Total Core Damage Frequency		3.30E-5	3.00E-5

It is important to consider the risk implications of new RCP seal material. While not previously quantified here, it is possible that the risk could increase as a result of this change. In general, core melting and vessel breach under high pressure conditions tends to produce higher probabilities of containment failure than low pressure sequences. Replacement of the seal material decreases the overall CDF, but may increase the frequency of high pressure sequences. Thus, this issue should be examined carefully before any changes are recommended.

2.4 Phase 3 - Implementation of Effective Emergency Response

Emergency response involves actions outside the plant to reduce public exposure to radiation during and after an accident. A specific emergency response will be comprised of some combination of evacuation, sheltering, decontamination, and interdiction strategies. Emergency response can be very site-specific, and is strongly influenced by population density, road systems, weather conditions, and interactions with and between local and state governments. Emergency response strategies vary from plant to plant. Some strategies are relatively simple, based primarily on evacuation within a ten mile radius, while others incorporate some accident-specific graded responses.

There is usually very little guidance concerning correlation of the emergency response with the anticipated progression of an accident. For example, evacuation should not be initiated if the containment has just failed or is being vented. Instead, sheltering followed by timely relocation should be considered. Further, there are many unknowns in the emergency response process. The sheltering effectiveness of different building types, long-term relocation criteria, and the criteria for land interdiction and crop disposal are all highly uncertain.

PRA information can assist the utilities and NRC in the emergency response decision-making process. For particular sets of conditions, i.e., plant states, site conditions, and weather conditions, a PRA framework can be used to evaluate the public health risk for various strategies. At the same time, the effects of in-plant actions, such as venting, can be factored into the process. A number of steps are involved in this process, including:

1. Characterization of possible source terms.

2. Evaluation of site conditions, including population characteristics and road conditions.

3. Evaluation of the operator's predictive capability.

4. Identification of possible short-term actions.

5. Identification of possible long-term actions.

6. Integral evaluation of alternative strategies.

Characterization of the source terms includes identification of significant plant damage states and the possible radionuclide releases that may result. Release timing and energy are particularly important. The possibility of no containment failure should also be included.

The local site conditions are important to the extent that they affect evacuation and sheltering options. The local communications and institutional structures are important, along with the demographics and the road system. Of particular importance in evacuation is the impact of local weather conditions, such as ice and snow storms, or external events, such as earthquakes.

Real world decisions need to account for the fact that the predictive capability of the operators is limited. Timely decisions are essential for such actions as sheltering or evacuation. On the other hand, unnecessary evacuations are costly and result in additional hazards. Thus, emergency response decisions are, of necessity, probabilistic decisions based on best estimates of the risks associated with each decision. Future analyses will be required to deal with all of the intricacies of optimizing emergency response in all possible situations. The strategies to improve emergency response could consider combinations of the following:

1. Improved training of personnel in the decision chain and of the local populace

2. Increased integration of the emergency response into operating procedures, based on prior and expected accident progressions

3. Instrumentation, including improved radiation monitors, to support decision making

4. Optimization of evacuation/sheltering strategies based on risk

5. Optimization of interdiction/decontamination strategies based on risk

The integrated PRA framework provides a unique capability for evaluating and optimizing emergency response plans that minimize the health and economic risk to the public.

2.5 Phase 4 - Prevention of Vessel Breach

If core damage is inevitable or has already occurred, then the goal of risk management is to arrest the degradation process and retain the fission products and core materials within the vessel and reactor coolant system. Recovery may be attempted while the fuel rods are intact, while corium is lying molten on the bottom of the vessel or anytime in between. The options available are limited and generally would involve restoration of vessel water inventory and primary system heat removal. Currently, there are no detailed procedures related to the timing and injection of water into an overheated core. There is usually little or no guidance beyond instructions to flood the core if at all possible. Further, the amount of actual experimental data dealing with reflooding a degraded core is extremely limited. Thus, as discussed earlier, flexibility is important and surprises should be considered likely. In this section, quantitative examples are not provided, but rather, we discuss some of the factors that are important in Phase 4 risk management and how the NUREG-1150 methods can be used in the development of appropriate Phase 4 strategies.

As discussed in Section 2.1, it is probably best to deal with these situations in terms of plant states and functional responses. There is no instrumentation to directly measure the state of the core, but much can be inferred from temperature, pressure, and radiation levels in the primary system. Of course, a key to evaluating the current situation is the existence of monitoring equipment that will survive the expected environments or at least fail in such a manner that the failure is itself an indication of the environment.

Functional responses to degraded cores are limited to injection of water and control of system pressure. However, there may be many variations of these responses. Low versus high flow rates, cold leg injection versus core spray, and high versus low pressure injection are examples of alternative injection scenarios that may lead to different outcomes, assuming that the operators have a choice. In evaluating various options using the NUREG-1150 methods, the following steps would be included:

1. Identify the risk important plant states.

2. Identify the possible plant states (symptoms) that could result in these scenarios.

3. Determine the ability of the operators to use available instrumentation to identify existing plant states.

4. Identify possible functional responses.

5. Evaluate the probability and consequences of potential outcomes to each functional response.

Once the evaluation is complete, then appropriate strategies can be selected and implemented. This implementation could involve procedures, guidance and hardware modifications along with modifications to training and plant practices.

The first step in this process identifies the types of sequences that will be important and the information and systems that will be available to the operators prior to vessel breach. For example, the availability of AC and DC power will determine the availability of much of the instrumentation and any systems with motor-driven pumps.

A variety of plant states may be possible, given a particular plant damage state scenario. Examples of the types of indicators that could be used to discriminate among the plant states include:

1. Reactor coolant system pressure.

2. Reactor coolant system temperature.

3. Radiation levels.

4. Reactor vessel water level.

5. Availability of steam generator (PWR) or power conversion system (BWR) heat removal.

6. Reactor coolant system integrity.

7. Containment pressure.

8. Containment temperature.

The plant states need only be delineated to the extent that each one could require a significantly different response to potential recovery actions.

After potential plant states are identified, it is important to understand the operator's ability to distinguish among the states. In some cases instrumentation may not be available, or worse, may be misleading due to the environmental conditions.

A number of different types of risk management strategies might be proposed under these conditions. These strategies can include:

1. Addition of improved instrumentation.

2. Use of nonsafety systems to provide makeup water.

3. Varying the rate and location of injection, depending on the particular plant state.

4. Increasing or decreasing the primary system pressure, as appropriate for the scenario.

The major goal of this phase is to obtain a coolable core and mitigate radionuclide releases; however, analysis of the possible outcomes of various actions is a complex process. For example, reflooding a degraded core can result in hydrogen generation, disruption of geometry, fuel-coolant interactions, etc. Some of these events may threaten the integrity of the reactor coolant system and/or the containment. Examples of specific considerations during reflood include:

1. Even a non-energetic quench of a hot core may produce enough steam to threaten steam generator tube integrity.

2. Addition of water could lead to rapid hydrogen generation. Thus, containment hydrogen control actions might be appropriate prior to core reflood.

3. Rapid flooding under depressurized conditions could lead to fairly energetic fuel-coolant interactions; thus, under low pressure conditions, a slow quench may be preferable. On the other hand, if the vessel eventually fails anyway, it is preferable for the system to be at low pressure to reduce the effects of direct containment heating.

While the current state of knowledge and uncertainty regarding information available to the operator do not support that a quench of the core should not be attempted, it is clear that there will be tradeoffs to consider when selecting the most appropriate method for cooling a degraded core. The NUREG-1150 methods provide a framework for evaluating each possible recovery scenario from a probabilistic standpoint to evaluate potential outcomes and their influence on overall risk. By providing an explicit mechanism for treating uncertainties, these methods make it possible to anticipate potential surprises and prepare the operators to recognize the symptoms of events that are not considered the most likely, but are nonetheless possible. Clearly, the final selection of preferable strategies should be supported by appropriate mechanistic analysis and any available experimental data.

2.6 Phase 5 - Retention of Fission Products

If the primary system boundary is breached, then fuel and radionuclides will be released to the containment, and risk management will be oriented toward preserving containment integrity and/or strategies to reduce off-site radioactive releases. At this point, the risk management environment is changed in a number of important ways. First, the plant state must be characterized by a different set of parameters, and the key diagnostic data are provided via different pathways. Second, longer time scales may now govern the accident. Third, the systems and actions available for responding to the accident are largely different. Finally, the interface with off-site emergency response decisions is at its most critical stage.

Despite the differences identified above, the approach to this phase of risk management is similar to that of Phase 4. In this section, quantitative evaluations of such strategies are not provided, but rather, the factors that influence the identification of options and how the NUREG-1150 methods can be used in the development process are discussed. The steps involved in developing such options include:

1. Identify the risk important scenarios.
2. Identify the possible plant states (symptoms) that could result in these scenarios.
3. Determine the ability of the operators to use available instrumentation to identify existing plant states.
4. Identify possible functional responses.
5. Evaluate the probability and consequences of potential outcomes to each functional response.

The first step in this process identifies the scenarios that will be important to risk. This scenario identification includes determination of the availability of containment systems. These systems include sprays, fan coolers, igniters, venting and isolation systems, ice condensers, suppression pools, and any system that can be used to inject water into containment.

The next step is to identify the possible plant states. Containment states both before and after vessel breach are important. Containment failure prior to vessel breach is possible in some scenarios, and the conditions in containment at the time of vessel breach can be very important. Further, in many cases knowledge of the history of the accident will help define the current containment state. For example, whether the reactor cavity is wet or dry may depend on the systems that have previously injected water into containment. The types of parameters that can be used to distinguish among the plant states include:

1. Containment pressure.

2. Containment temperature.

3. Containment integrity.

4. Availability of containment heat removal.

5. Steam and combustible gas concentrations.

6. Presence of water in the reactor cavity.

7. Radiation levels.

8. Availability of fission product scrubbing systems (sprays, pools, or filtered vents).

Instrumentation exists in most containments to either directly determine or infer most of the parameters identified above. However, this equipment is generally not designed to operate in the environments that may be produced when molten corium is present in containment and will likely fail or display erroneous output. Therefore, caution must be used when interpreting the instrument readings.

The functions of importance are removal of heat to preserve containment integrity and maximum retention of fission products. A number of different strategies may be considered to accomplish these functions which are given below with the phases that are affected:

1. Addition of improved instrumentation (2,4,5).

2. Management of combustible gas (4,5).

3. Injection of water into containment (5).

4. Venting strategies (2,5).

5. Alternate methods for containment heat removal (2,5).

6. Alternate methods for reducing suspended aerosols (5).

7. Strategies for controlling high pressure melt ejection (5).

The analysis and evaluation of Phase 5 strategies is a complex process. Numerous phenomena must be considered, including core-concrete interactions, direct containment heating, combustion, containment structural response, and fission product transport. Negative as well as positive effects of actions or systems must be understood in order for the integrated assessment of risk management options to be complete. For example, three relevant considerations are:

1. Opening and reclosing a containment vent prior to vessel breach will reduce the baseline pressure in containment and thereby decrease the potential for containment failure at vessel breach; however, if core damage has occurred, this will accelerate the release of noble gases and, potentially, other more significant radionuclides, particularly if the vent cannot be reclosed prior to vessel breach.

2. Flooding the reactor cavity may decrease the likelihood of substantial core-concrete releases; however, associated steam production can accelerate the rate of pressure buildup so that the containment may fail earlier in scenarios in which containment heat removal cannot be reestablished.

3. With the containment at high pressure and high steam concentrations, the actuation of sprays following power recovery will wash out suspended fission products, but may de-inert the containment atmosphere, leading to hydrogen burns.

The NUREG-1150 methodology allows for a probabilistic evaluation of the risk implications of various Phase 5 risk management actions. Both best estimate predictions and the identification of alternative outcomes can be produced. Prior knowledge of the possible alternative outcomes will allow the operators and response teams to recognize these outcomes and respond with revised strategies as the accident proceeds.

2.7 Example of Integrated Risk Management Strategy

This report has examined the individual effect of separate risk management options on plant core damage frequency or risk. This shows the analyst the relative importance of each option in reducing risk or core damage frequency. However, any realistic risk management program will include numerous actions dealing with all five phases. The ability of a PRA framework to evaluate the interactions among these options is crucial. It is outside the scope of this report to provide a complete integrated analysis; however, in this section, the combined effect of several phase 1 and 2 risk management strategies are examined. Chosen for this combined strategy example are four future risk management strategies identified in sections 2.2 and 2.3 for the Surry plant. These include:

- addition of an independent diesel generator
- use of an onsite gas turbine generator
- use of improved RCP seals
- extension of battery life

All of the above options address station blackout sequences, which account for two-thirds of the Surry core damage frequency. To evaluate the combined effect of these options on the core damage frequency, plant models were changed to reflect each option. Although not true generally, the reduction in the core damage frequency due to these combined options is not as large as the combined effect of the options evaluated individually. Most of the plant damage states, all of which are station blackout, are affected by more than one risk management strategy. Therefore, the combination of risk management options has less effect on the core damage frequency, and subsequently, the total reduction in the core damage frequency is not as great as the sum of the individual reductions for each option evaluated separately.

The two options of utilizing improved RCP seals and extension of battery life simply involve changing basic event probabilities. The intermediate increase in battery life of 8 hours was used for this combined option example. The other two options to enhance onsite emergency power reliability, addition of a diesel generator and utilization of a gas turbine generator, require the recovery of cutsets within the applicable plant damage states, as described in previous sections. The primary and intermediate plant damage states affected by each option are given in Table 2.9. The designators for these intermediate plant damage states

Table 2.9

Plant Damage States Affected by
Risk Management Strategies

Primary PDS	Intermediate PDS	New DG	GTG	New RCP Seals	Extended Batt Life
PDS1	S2RRR-RCR	X			
PDS1	S2RRR-RDR	X			
PDS1	S3RRR-RCR	X	X	X	
PDS1	S3RRR-RDR	X	X	X	
PDS1	TRRR-RCR	X	X	X	X
PDS1	TRRR-RDR	X	X	X	X
PDS1	TRRR-RDY	X	X		X
PDS2	TRRR-RSR	X			

are defined in Section 2.2-1 (2.1 and 2.2). Quantification using TEMAC (point estimate mode) was performed on the intermediate and primary plant damage states affected by this combined strategy, with the results given in Table 2.10. The core damage frequency of 1.2E-5 for this combined strategy represents a factor of 2.7 reduction from the base case value.

Table 2.10

Plant Damage State Changes Due to
Combined Risk Management Strategies

Plant Damage State	Type	Existing CDF	New CDF
S2RRR-RCR	SBOQ	1.67E-6	6.68E-8
S2RRR-RDR	SBOQ	6.03E-7	2.41E-8
S3RRR-RCR	SBOS	2.41E-7	2.14E-9
S3RRR-RDR	SBOS	6.21E-6	5.60E-8
TRRR-RCR	SBOB	1.72E-8	7.64E-10
TRRR-RDR	SBOB	7.09E-7	3.15E-8
TRRR-RDY	SBOB	7.17E-6	1.06E-7
TRRR-RSR	SBOL	4.60E-6	1.39E-7
Total SBO Frequency		2.12E-5	4.62E-7
Total Core Damage Frequency		3.30E-5	1.24E-5

3. EVALUATION OF CURRENT RISK MANAGEMENT PRACTICES

As discussed in Chapter 1, an integrated PRA framework is effective in evaluating the efficacy of current risk management practices at a nuclear power plant. These practices include hardware improvements already made and operating procedures in place. In this chapter, we will discuss specific examples of risk management practices and their effect on the core damage frequency and risk at two of the plants in question. Both qualitative and quantitative examples are presented.

In principle, the methods used to evaluate current practices are straightforward. In order to determine the worth of risk management practices already credited at the plant in the NUREG-1150 analysis, the CDF/risk can simply be calculated with and without a particular practice in place. However, in practice this can be a complex process, if removing an option changes the fundamental models in the PRA. For phase 1 and 2 options, changes to basic event data or operator recovery actions are easy to evaluate, while changes to fault trees require more effort. Similarly, for phases 3 to 5, changes that affect input parameters for the accident progression event tree, source term and consequence models are readily evaluated, while changes to the models themselves require more effort. In this report, phase 1 and 2 options are emphasized and quantitative examples provided for selected cases.

There is one important factor to consider when evaluating the effectiveness of current risk management procedures, as opposed to evaluating proposed new options. In adding new options, the result should generally be to reduce the CDF/risk from identified dominant accident sequences without introducing any new sequences. On the other hand, evaluating the benefit of current plant practices involves evaluating the CDF/risk assuming the practice were not installed or operational at the plant. This means that the sequences and phenomena previously screened out as probabilistically unimportant are likely to be reintroduced into the analysis. Where possible in this report, requantification of any reintroduced sequences is provided, and in other cases, a qualitative discussion is provided.

3.1 Risk Management Practices Affecting All Plants

There are numerous improvements that have occurred throughout the nuclear industry since Three Mile Island in the form of changing regulations and industry initiatives. Many of these have such pervasive effects on the plant that their impact is difficult to quantify, but their importance should be noted.

Probably the most risk-significant changes have occurred in the areas of operating procedures and operator training. All of the plants analyzed have, to some extent, incorporated symptom-based emergency operating procedures in place of event-based procedures. Since events are defined or identified by symptoms, changes to symptoms are less important than the flexibility in operator response now possible because an event no longer needs to be precisely defined. Further, the operators have been trained much more rigorously in the use of these procedures. These changes have been enhanced by the development of improved Safety Parameter Display Systems (SPDS) that help reduce the confusion that arose during the TMI incident. Overall, these changes have resulted in PRA predictions of significantly lower human error probabilities across the board. Additionally, due to improved training and procedures for operators, PRAs now consider additional operator recovery actions. The use of alternative injection systems and other actions are now explicitly included in many emergency procedures. As a result of all of these changes, human error plays a much smaller role in the NUREG-1150 analyses than might be anticipated based on a review of older PRAs.

Numerous other NRC and industry sponsored initiatives have also reduced severe accident risks. These include trip reduction programs, ATWS and station blackout rulemaking efforts, and improved maintenance programs. It is important to note that these efforts have led to the reduction or elimination of many accident sequences previously thought to be dominant and to their replacement by other sequences that previously were relatively less important. For some sequences the perceived risk is reduced simply because we now have a more quantitative understanding of the sequence. The ATWS sequences are examples of where a combination of improved operator preparedness and a more realistic assessment of sequence progression have yielded a lower prediction of risk than that of previous studies.

3.2 Risk Management Practices at Surry

In this section, we present examples of significant risk management efforts at Surry. This discussion is not intended to be comprehensive, but rather will acknowledge a few key efforts and illustrate how the effectiveness of these efforts can be evaluated using a PRA framework.

We will discuss three particular Phase 2 risk management practices currently incorporated at Surry and estimate their benefit to the plant. These practices would be applicable to many other U.S. PWRs, although the quantitative impact would vary from plant to plant. These Phase 2 practices include:

1. The use of feed and bleed primary system cooling,

2. The use of secondary blowdown to remove heat from the primary system, and

3. The use of High Pressure Injection (HPI) and Auxiliary Feedwater (AFW) system cross-connect injection from Unit 2.

Each of these sets of procedures has had an impact on the Surry core damage frequency. The specific evaluations are presented in the following sections.

3.2.1 Feed and Bleed Cooling

The NUREG-1150 analysis for Surry includes the utilization of feed and bleed cooling for those sequences in which all feedwater to the steam generators is lost. In these sequences, the feedwater inventory is boiled off from the steam generators, causing insufficient heat removal from the primary system. Feed and bleed cooling restores heat removal from the core using HPI (High Pressure Injection) to inject water into the reactor vessel and using the pressurizer relief valves to allow discharge of inventory from the primary system. In order to be successful, feed and bleed cooling must be initiated before the steam generators dry out. Otherwise, the primary system pressure may rise to the point where sufficient injection can not be provided, even with the pressurizer relief valves open.

An evaluation of the effectiveness of feed and bleed cooling in reducing the core damage frequency requires two steps. First, dominant Surry plant damage states were requantified assuming that feed and bleed cooling was not available. Second, sequences that had previously been screened out based on a low probability were examined to determine if they might have been dominant without feed and bleed cooling available.

The current Surry model includes two basic events to account for feed and bleed cooling in the event of a loss of all feedwater. These events represent operator failure to initiate high pressure injection, HPI-XHE-FO-FDBLD, and operator failure to properly operate the power-operated relief valves (PORVs), PPS-XHE-FO-PORVS. If either of these basic events is set to 1.0, no credit is given for feed and bleed cooling. These events appear in the following primary plant damage state (PDS), which is described in Reference 4.

> PDS1 - Represents transient initiators leading to loss of main feedwater, followed by loss of all auxiliary feedwater and ultimate failure of feed and bleed cooling due to failure of high pressure injection or failure of both PORVs to open.

PDS1 represents the combination of the two similar intermediate PDSs, TIYY-YNY and TNYY-YNY, which are described in Ref. 4. TIYY-YNY contains cutsets with the PPS-XHE-FO-PORVS basic event and TNYY-YNY contains cutsets with the HPI-XHE-FO-FDBLD basic event. Both intermediate plant damage states represent transients leading to loss of all feedwater (TML). Feed and bleed cooling is the only way to remove heat for accident sequences in these intermediate PDSs. The HPI basic event was set to 1.0 in this sensitivity study, which is sufficient to fail feed and bleed cooling. Therefore, requantification using the Top Event Matrix Analysis Code (TEMAC) was only performed on the TNYY-YNY intermediate PDS. The resulting point estimate of the total core damage frequency was found to be 4.2E-5, compared to a value of 3.3E-5 with feed and bleed cooling available. The results for the primary plant damage state and the total core damage frequency are summarized in Table 3.1.

To complete the estimate of the effect of feed and bleed cooling, we considered the additional contributions of the previously non-dominant sequences. These contributions are then added to the total core damage frequency estimated in the previous paragraph. Table 3.2 shows the sequences and associated frequencies that would exist if feed and bleed cooling were not available. These sequences were identified by examining the listing of dominant accident sequences from Table 4.10-4 in Reference 4. Sequences in this table were included in Table 3.2 if 1) successful operation of the charging pump system in the feed and bleed mode ($/D_2$) and/or the opening of two PORVs for feed and bleed (/P) occurred and 2) they were previously eliminated from the analysis due to low probability. The frequency given for each sequence in Table 3.2 is the 'after recovery' frequency, given in Table 4.10-4 of Reference 4, divided by the probability of the feed and bleed failure event for that particular sequence. Frequencies calculated for these sequences include the recovery action, AFW-XHE-FO-UNIT2, which represents an operator-initiated cross-connect to the Unit 2 auxiliary feedwater system. The contribution to the core damage frequency of all sequences that previously were eliminated and in which feed and bleed cooling was given credit was found to be 1.29E-6. The point estimate for the total core damage frequency for Surry if feed and bleed cooling were not available then becomes 4.3E-5, compared to the current value of 3.3E-5.

3.2.2 Secondary Blowdown

Within the past decade and especially after the TMI-2 accident, operators have been instructed to be more active in depressurizing and cooling down the reactor under accident conditions. In the event of small break initiators (S_2, S_3), operators are instructed to perform a controlled cooldown and depressurization of the primary system in order to forestall the initiation of ECCS recirculation. In the event that the primary

Table 3.1

Changes to the Core Damage Frequency(CDF) Without Feed and Bleed Cooling

Plant Damage State	Description	Existing CDF	New CDF
PDS1	Loss of All Feedwater Transient	1.6E-6	1.0E-5
Total Core Damage Frequency		3.3E-5	4.2E-5

Table 3.2

Additional Sequences Affected by Feed and Bleed Cooling

Sequence	Description	CDF
T_1LP	Loss of off-site power, failure of AFW and PORVs	1.1E-6
T_3LMP	Transient with loss of main feedwater, AFW, and PORVs	2.3E-7
Total Contribution		1.3E-6

system can not be or is not depressurized, high pressure recirculation will be demanded upon depletion of the Refueling Water Storage Tank (RWST). In the event that high pressure recirculation (H_2) fails, the operator may quickly depressurize the secondary side by blowing down the steam generators, thus cooling and depressurizing the primary loop. The reduced pressure in the primary system would allow the low pressure systems to inject into the vessel. These actions may also be useful during TQD_2 type sequences in which at least one PORV is stuck open, resulting in a transient-induced small LOCA.

Secondary blowdown is unlikely to become an important factor in recovering from accidents at Surry. From a safety analysis standpoint, a number of sequence types can be identified for which secondary blowdown would be a logical and necessary alternative. Specifically, S_2H_2, S_3H_2 and TQD_2 type sequences would require secondary blowdown to cool the primary system. However, the number of failure events that must occur prior to the need for secondary blowdown cause the sequence frequency to drop below the risk significant cutoff value, 1.0E-7, even without secondary blowdown. Therefore, secondary blowdown never becomes a significant event at Surry with regard to probabilistic safety analysis.

For example, the LOCA sequence S_3H_2 (representing the occurrence of the small LOCA initiating event, S_3, and failure of the High Pressure Recirculation system, H_2) includes other implicit failures which decrease this sequence probability. These are operator failure to effect a controlled depressurization of the primary system (probability of 2.2E-2) and operator failure to cross-connect the high pressure injection system with the Unit 2 RWST (probability of 3.6E-2). Included in this sequence are the events of the S_3 initiator and failure of High Pressure Recirculation with probabilities of 1.3E-2 and 1.3E-4, respectively.

Secondary blowdown could next be initiated to cool and depressurize the primary system, but the sequence is already probabilistically insignificant at a frequency of 1.3E-9. Sequences are disregarded in the Surry analysis if they have a frequency below 1.0E-7. Therefore, secondary blowdown is not considered a significant risk reduction measure at Surry. At plants without cross-connects of high pressure injection and automatic switchover to recirculation, secondary blowdown could be much more important.

3.2.3 Unit 2 Cross-Connects

The Surry Unit 1 plant procedures direct the operator to recover from the loss of the High Pressure Injection (HPI) system or from loss of the Auxiliary Feedwater (AFW) system by operator-initiated cross-connection to the analogous system at Unit 2. This hardware change was incorporated at the plant, prior to the NUREG-1150 analysis, to supply additional redundancy to the HPI and AFW systems.

The alignment of either of the cross ties requires operator action. For the AFW system, flow from the Unit 2 AFW pumps is provided to the discharge headers of the Unit 1 AFW system. The operator must isolate the auxiliary feedwater pumps from the steam generators at Unit 2, open one of two motor operated valves (MOVs) in parallel to establish the cross-connect pathway, and manually start the Unit 2 AFW pumps. For the HPI system, flow from the Unit 2 charging pump C is provided to the discharge line of the Unit 1 C train charging pump through a cross-connect created by the opening of two MOVs in series. The Unit 2 C train pump must be isolated from the other charging pumps, and the C pump must then be started.

While the added redundancy of cross-connecting is beneficial, it is important to note that new system failure modes have been created by the cross-connects. A flow diversion pathway can be created through an inadvertently open cross-connect valve. This potential fault is modeled in the revised Surry NUREG/CR-4550 analysis [4].

The alignment of the Unit 1 and Unit 2 HPI and AFW systems for cross-connect injection is modeled as a recovery action for both systems. Five event types are used for the HPI system cross tie and three event types for the AFW system cross tie. These represent the failure of the operator to properly cross tie the systems under various conditions. Two additional basic events model cross ties to the Unit 2 HPI system to cool the reactor coolant pump seals during station blackout. All of these events are described in Table 3.3.

The analysis of the importance of the cross-connects includes two parts. First, the dominant PDSs were examined, and then sequences that were previously screened out were checked to determine if they would be added to the dominant list in the absence of cross-connect injection.

Table 3.3

AFW and HPI Cross-Connect Basic Events

Basic Event	Description	Probability
AFW-XHE-FO-UNIT2	Operator fails to Xconn AFW during transients with all power available	3.6E-2
AFW-XHE-FO-U1SBO	Operator fails to Xconn AFW during station blackout at Unit 1 with power at Unit 2	8.2E-2
AFW-XHE-FO-U2SBO	Operator fails to Xconn AFW during station blackout at both units	1.25E-1
HPI-XHE-FO-UN2H1	Operator fails to Xconn HPI to Unit 2 HPI or RWST during S_2H_1 and S_3H_1 sequences	1.6E-3
HPI-XHE-FO-UN2S2	Operator fails to Xconn HPI to Unit 2 during S_2D_1 sequences	3.1E-1
HPI-XHE-FO-UN2S3	Operator fails to Xconn HPI to Unit 2 during S_3D_1 sequences	4.4E-2
HPI-XHE-FO-20DH2	Operator fails to Xconn HPI to Unit 2 HPI or RWST during $S_2O_DH_1$ and $S_2O_DH_2$ sequences	4.3E-3
HPI-XHE-FO-30DH2	Operator fails to Xconn HPI to Unit 2 HPI or RWST during $S_3O_DH_1$ and $S_3O_DH_2$ sequences	2.1E-3
REC-XHE-FO-SCOOL	Operator fails to Xconn to Unit 2 HPI to cool RCP seals during station blackout	1.25E-1
NOTW2	Success of RCP seal cooling from Unit 2 during station blackout	8.1E-1

In order to reevaluate the point estimate of the core damage frequency for the Surry PDSs without credit for cross ties, the probabilities for eight of the ten basic events representing injection cross-connects were given a value of 1.0. One basic event, REC-XHE-FO-SCOOL, was set to 0.94 instead of 1.0 to eliminate double counting of some cut sets. Another basic event, NOTW2, was set to zero to ensure failure of RCP seal cross-connect cooling. All PDSs were examined to ensure that no double counting of cut sets occurred as a result of setting the other basic event probabilities to 1.0. Quantification was performed using TEMAC, and the resulting point estimate of the core damage frequency was found to be 1.02E-4, triple the original value of 3.30E-5. The results for the intermediate and primary PDSs and total plant are given in Tables 3.4 and 3.5.

The sequences previously screened out that could become important are shown in Table 3.6. These sequences were identified by examining the listing of dominant accident sequences from Table 4.10-3 of Reference 4. Those sequences present in Table 4.10-3 which were eliminated from the analysis in Reference 4 and contained an AFW or HPI cross-connect recovery action are included in Table 3.6. The sequence frequency without cross-connect injection was calculated by dividing the post-recovery sequence frequency (from Table 4.10-4 in Reference 4) by the applicable cross-connect recovery probability. The sum of all these sequence frequencies is 1.19E-5. The point estimate for the total core damage frequency assuming cross-connect injection were not available then becomes 1.14E-4. The inclusion of cross-connect injection has significantly reduced the potential for core damage at Surry.

As shown in the tables, a significant number of sequences and plant damage states are affected by the cross-connections. The plant damage states involving steam generator tube rupture have risk significance because of the potential for containment bypass. The station blackout plant damage states are also significant because of the potential for early containment failure.

3.3 Risk Management Practices at Peach Bottom

In this section, we present some examples of significant risk management efforts at Peach Bottom. As with the discussion for Surry, this discussion is not intended to be comprehensive, but rather will acknowledge a few key efforts and illustrate how the effectiveness of these efforts can be evaluated using a PRA framework.

Section 4.2 describes several actions at Peach Bottom that could be considered risk management actions. Further, the discussion in Section 3.1 concerning risk management actions at all plants applies to Peach Bottom. In this section we will discuss three particular types of risk management procedures or practices currently in place at Peach Bottom and evaluate their expected benefit. These are Phase 1,2 and 4 procedures

Table 3.4

Changes in Intermediate Plant Damage States Due to AFW and HPI Cross-Connection

PDS	Description	Previous CDF	New CDF
GIYY-YNY	Steam generator tube rupture, AFW fails	1.05E-7	3.27E-7
GNYY-YXY	Steam generator tube rupture, injection fails	1.74E-7	2.11E-6
S2LYY-YYN	Small LOCA, recirc fails	4.26E-7	7.89E-7
S3LYY-YYN	Small LOCA, HPI fails	5.39E-7	7.34E-6
S3RRR-RCR	Station blackout with seal LOCA	2.41E-7	9.23E-7
S3RRR-RDR	Station blackout with seal LOCA	6.21E-6	2.35E-5
TIYY-YNY	Loss of MFW and AFW	8.44E-7	2.34E-5
TNYY-YNY	Loss of MFW and AFW, injection fails	7.16E-7	1.99E-5
TRRR-RCR	Station blackout with battery depletion	1.72E-8	3.47E-8
TRRR-RDR	Station blackout with battery depletion	7.09E-7	1.41E-6
TRRR-RDY	Station blackout with battery depletion	7.17E-6	0
TRRR-RSR	Station blackout, AFW fails	4.60E-6	7.59E-6
Total Core Damage Frequency		3.30E-5	1.02E-4

Table 3.5

Changes to Plant Damage States Due to AFW and HPI Cross-Connections

PDS	Description	Previous CDF	New CDF
PDS1	Slow Station Blackout	1.44E-5	2.59E-5
PDS2	Fast Station Blackout	4.60E-6	7.59E-6
PDS3	LOCAs	9.65E-7	8.13E-6
PDS5	Transients	1.56E-6	2.01E-5
PDS7	SGTRs	2.79E-7	2.44E-6
Total Core Damage Frequency		3.30E-5	1.02E-4

that would be applicable to many other U.S. BWRs, although the quantitative impact would vary from plant to plant. These procedures are:

1. Use of the Primary Containment Venting system to alleviate containment overpressurization,

2. Use of the High Pressure Service Water (HPSW) as an alternate injection system, and

3. Improved Diesel Generator (DG) maintenance practices.

Each of these sets of procedures has had an impact on the Peach Bottom core damage frequency. The specific evaluations are presented in the following sections.

3.3.1 Primary Containment Venting

The Primary Containment Venting (PCV) system is used as a Phase 2 and Phase 4 strategy to prevent primary containment overpressurization during accident sequences in which all containment heat removal is lost. Most of these sequences involve failure of the Residual Heat Removal (RHR) systems to perform successfully in any one of several modes that can remove heat from containment.

Table 3.6

Non-Dominant Sequences Quantified with HPI and AFW Cross Connects Unavailable

Accident Sequence	Applicable Cross Connect Recovery	CDF After Recovery	CDF Without Cross Connect
T_1LP	AFW-XHE-FO-UNIT2	7.5E-8	2.08E-6
T_1LD_2	AFW-XHE-FO-UNIT2	6.4E-8	1.78E-6
T_2LH_1	AFW-XHE-FO-UNIT2	1.4E-8	3.89E-7
T_3LMP	AFW-XHE-FO-UNIT2	1.6E-8	4.44E-7
T_3LMD_2	AFW-XHE-FO-UNIT2	1.6E-8	4.44E-7
T_3QH_1	HPI-XHE-FO-UN2H1	<5E-10	3.13E-7
$T_{5A}LP$	AFW-XHE-FO-UNIT2	1.4E-7	3.89E-6
$T_{5A}LD_2$	AFW-XHE-FO-UNIT2	9.0E-9	2.50E-7
$T_{5B}LD_2$	AFW-XHE-FO-UNIT2	9.0E-9	2.50E-7
$T_7D_1Q_S$	HPI-XHE-FO-UN2S3	4.8E-9	1.09E-7
S_2H_1	HPI-XHE-FO-UN2H1	7.2E-10	4.50E-7
$S_3W_3H_1$	HPI-XHE-FO-UN2H1	5.9E-10	3.69E-7
$S_3O_DH_2$	HPI-XHE-FO-20DH2	<5E-10	1.16E-7
$S_3O_DH_1$	HPI-XHE-FO-20DH2	4.6E-9	1.07E-6
Total Contribution			1.19E-5

Availability of PCV plays a significant role in TW sequences. TW-type sequences are those in which core cooling is initially successful, but containment cooling fails. Containment failure can flood the reactor building with steam, possibly leading to failure of core cooling equipment. Containment venting can prevent this failure, provided that the venting itself does not also lead to steam in the reactor building. Peach Bottom has a six inch Integrated Leak Rate Test (ILRT) Line that is a hard pipe vent line through the reactor building. The use of this line will not produce steam flooding. On the other hand, this line is not adequate for all accident scenarios. Other lines are available, but some contain ductwork that is likely to fail when pressurized, thus introducing steam into the reactor building. The preferred primary containment vent paths, in the order of recommended use, are:

1. 2-inch torus vent to the Standby Gas Treatment System (SBGT)
2. 2-inch drywell vent to the SBGT
3. 6-inch ILRT line from Torus
4. 18-inch torus vent path to SBGT
5. 18-inch torus supply path
6. ILRT line from the drywell
7. 18-inch drywell vent path to SBGT
8. 18-inch drywell supply path
9. two 3-inch drywell sump drain lines

The 2-inch lines are also hard pipe, but are not adequate for most of the sequences of interest. Use of the 18-inch lines can lead to steam flooding in the reactor building.

Another concern when venting is that saturation conditions in the suppression pool can result. These conditions can lead to failure of the Low Pressure Coolant Injection (LPCI) or Low Pressure Core Spray (LPCS) pumps in the recirculation mode resulting from lack of adequate Net Positive Suction Head (NPSH). However, this is usually not a problem at Peach Bottom because other low pressure injection sources that do not use the suppression pool as an injection source, such as High Pressure Service Water (HPSW) or Condensate, can provide needed coolant makeup.

The current venting procedures require that a vent path be established if the containment pressure rises to 100 psig. At this pressure, the suppression pool temperature will be approximately 337°F, which is above the failure temperature for High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC). RCIC may have previously tripped due to high turbine exhaust pressure. The remaining high pressure system is the Control Rod Drive (CRD) system. If CRD is not available, the operators must depressurize the primary system and initiate low pressure injection. This requires maintaining the containment pressure below 115 psig, or the safety relief valves will close and repressurize the primary system. Thus, for the TW sequences, two different venting success criteria exist:

1. With CRD operating - successful venting after 100 psig is reached, but before containment failure. The calculated human error probability is 0.01.

2. With CRD failed - successful venting after 100 psig is reached, but before 115 psig is reached. The calculated human error probability is 0.5.

These human error probabilities come from Appendix C of Reference 6. The second case represents a conservative screening value. A more refined calculation was not performed, since no TW sequences with CRD failure were dominant in the analysis after screening. There are a few other sequences, such as small LOCAs with loss of heat removal, that are affected by venting. However, the dominant sequences, Station Blackout and ATWS, are not affected by venting. During Station Blackout, venting can not be accomplished from the control room during station blackout, and operator venting actions in the reactor building would be hazardous. Also, the venting capacity is not considered to be adequate for most ATWS sequences.

This analysis considered the impact of venting on both the dominant accident sequences (>1E-8) and those sequences that might have been dominant without the benefits of containment venting. None of the final dominant accident sequences included primary containment venting as an event. Therefore, venting had no impact on these sequences. Thus, our analysis concentrated on those sequences that were found to be non-dominant with containment venting present. The actual quantification of the importance of venting on the previously non-dominant sequences is a complex process, performed here in an approximate manner.

The accident sequence quantification from the Ref. 6 analysis must be reviewed to begin this process. First, the output of the cut set screening process from the PCV fault tree solution (obtained from SETS computer run results) in Reference 6 was examined. The top four cut sets were shown to be:

1. 5E-1 PCV-XHE-FO-PCV
2. 5E-2 LOSP*RBC-XHE-FO-SWCH
3. 5E-2 LOSP*CRD-XHE-FO-BRKRS
4. 5E-2 LOSP*RBC-XHE-FO-LCVAL

The values for the four cut sets given above sum to a value of 0.65 out of a total of 0.671 for the entire PCV system. These cut sets comprise 97% of the unavailability of the PCV system, given that power is available to open the containment venting valves. PCV human error probabilities were treated in the following manner in the NUREG-1150 analysis. The first cut set, comprised only of the basic event PCV-XHE-FO-PCV (operator failure to vent), was initially given a conservative (screening) probability of 0.5. If this basic event appeared in a dominant cut set, a more realistic probability (such as 0.01) was needed to more accurately model this human interaction. The screening value of 0.5 was replaced with the more realistic probability for subsequent accident sequence quantification. A general discussion of the technique used to determine the new basic event probability can be found in Appendix C of Reference 6. The other three cut sets involve human error basic events (...-XHE-...) which were initially assigned screening probabilities (0.5). As above, if these basic events appeared in dominant cut sets, more realistic values were needed for each and the screening values were replaced. Accident sequences were then requantified with more realistic system models. The major PCV dependencies are AC power and instrument air. In nearly all cases, if venting is possible at all (i.e., power and air is available to the valves), then the PCV failure probability is dominated by the failure of the operator to vent.

To determine the significance PCV has on the non-dominant sequences, all of the Peach Bottom event trees were reviewed. The success branches for PCV were ignored since they do not exist if the PCV system is removed from the tree. All of the non-dominant sequence failure branches were traced. There are approximately 2000 sequences containing PCV that were previously screened out.

These sequences were requantified with the PCV system eliminated from the event tree. The PCV event tree designator or symbol is a "Y". Table 3.7 is a compilation of these sequences listing the accident sequence numbers, estimated frequencies and approximate "Y" event probabilities assigned to each sequence from Table 4.10-1 of Reference 6. The "Y" event probability is specific to each sequence. Table 3.7 also lists the corresponding event tree sequences, new estimated frequencies, relevant comments and whether the sequence could be screened out. Some of the 2000 sequences have frequencies below the cutoff value of 1E-8 without consideration of the "Y" event and were eliminated from the requantification.

To determine these new estimated sequence frequencies, probabilities for PCV system failure from the NUREG-1150 analysis were utilized. Sequence frequency estimates from the NUREG-1150 analysis were divided by the appropriate PCV failure probability to estimate sequence frequencies without credit for the PCV system. Ideally, a SETS run would have been performed for the remaining sequences (approximately 1000) and the use of approximate frequencies would not be necessary. Additional SETS analysis was not feasible with the time and resources available. Therefore, each sequence was quantified by an estimated frequency.

Some of the "Y" event probabilities used in the initial quantification were stated in the comment sections in Table 4.10-1 of Reference 6. For sequences not covered in this way, the success or failure of the Control Rod Drive (CRD) system determined the appropriate "Y" event probability. If CRD is unavailable, a value of 0.5 was chosen for failure to perform venting. If CRD is available, the time between reaching the venting set-point and containment failure is sufficient to allow a third independent check/correction in the procedure, which reduces the value to 0.01. Refer to Tables C-51 through C-58 in Appendix C of the revised Peach Bottom NUREG/CR-4550 report [6], for a more complete description of the derivation of these values. Note that if CRD is available, then the operator may not need to vent in order to prevent core damage, since CRD may continue operation after containment failure.

(text continued on page 3-47)

TABLE 3.7

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
2	A-8	<6E-9	0.1	No	<6E-8	
4	A-16	<6E-9	0.1	No	<6E-8	
6	A-23,29	<1E-9	0.1	Yes	<1E-8	
9	S1-8	<1E-8	0.1	No	<1E-7	
11	S1-16	<1E-8	0.1	No	<1E-7	
13	S1-24	<1E-8	0.1	No	<1E-7	
15	S1-33,41,49	<1E-8	0.1	No	<1E-7	
18	S1-57,63,69	<1E-9	0.1	Yes	<1E-8	
20	S1-76,82,88	<1E-9	0.1	Yes	<1E-8	
25A	S2-4-9,10,12	<1E-9	.01	No	<1E-7	
26	S2-4-19,20,21,26,27,28, 33,34,35,40,41,42	<3E-9		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
30	S2-7-9,10,12	<3E-9	.01	No	<3E-7	
	S2-7-19,20,21,26,27, 28,33,34,35,40,41,42	<3E-9		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
31	S2-10-9,10,12,19, 20,21	<1E-8		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
32	S2-13-7,8,10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
33	S2-16-7,8,10,15,16,17	<1E-10		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
34	S2-19-7,8,10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
38	S2-24-9,10,12	<1E-8	.01	No	<1E-6	
	S2-24-19,20,21,26,27, 28,33,34,35,40,41,42	<1E-8		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
40	S2-27-9,10,12	<1E-8	.01	No	<1E-6	
	S2-27-19,20,21,26,27, 28,33,34,35,40,41,42	<1E-8		Yes		Sequence(s) previously Quantified (Table 4.10-1)[1] without PCV and eliminated
41	S2-30-7,8,10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
42	S2-33-7,8,10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
43	S2-36-7,8,10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
47	S3-2-4-9,10,12,19,20, 21,26,27,28,33,34,35,40, 41,42	<1E-9		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
	S3-2-7-9,10,12,19,20, 21,26,27,28,33,34,35,40, 41,42	<1E-9		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	S3-2-10-9,10,12,19,20, 21	<1E-9		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
	S3-2-13-7,8,10,15,16, 17	<1E-9		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
	S3-2-16-7,8,10,15,16, 17	<1E-9		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
	S3-2-19-7,8,10,15,16, 17	<1E-9		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
	S3-2-24-9,10,12,19, 20,21,26,27,28,33,34, 35,40,41,42	<1E-9		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
	S3-2-27-9,10,12,19,20, 21,26,27,28,33,34,35,40, 41,42	<1E-9		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
	S3-2-30-7,8,10,15,16, 17	<1E-9		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
	S3-2-33-7,8,10,15,16, 17	<1E-9		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
	S3-2-36-7,8,10,15,16 17	<1E-9		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated
51	T1-4-7,8,10	<1E-8	1E-2	No	<1E-6	TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
53	T1-4-15,16,17,22,23,24, 29,30,31	<5E-9	.5	Yes	<1E-8	Sequence(s) below "cutoff" TW Sequence(s)
57	T1-6-7,8,10	<1E-8	1E-2	No	<1E-6	TW Sequence(s)
58	T1-6-16,17,18,24,25,26, 32,33,34	<1E-8		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
61	T1-10-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T1-10-15,16,17,22,23, 24,29,30,31	<1E-8	.5	No	<2E-8	TW Sequence(s)
63	T1-12-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T1-12-16,17,18,24,25, 26,32,33;34	<1E-8		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
65	T1-16,7,8,10	<1E-9	.01	No	<1E-7	TW Sequence(s)
67	T1-16-15,16,17	<1E-9	.5	Yes	<2E-9	Sequence(s) below "cutoff" TW Sequence(s)
68	T1-20-7,8,10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified (Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
70	T1-24-7,8,10	<1E-8	1E-2	No	<1E-6	TW Sequence(s)
72	T1-24-15,16,17	<1E-9	.5	Yes	<2E-9	Sequence(s) below "cutoff" TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
77	T1-29-5,6,7	<1E-10	.01	Yes	<1E-8	Sequence(s) below "cutoff" TW Sequence(s)
79	T1-29-12,13,14	<1E-10	.01	Yes	<1E-8	Sequence(s) below "cutoff" TW Sequence(s)
81	T1-29-19,20,21	<1E-8	.01	No	<1E-6	TW Sequence(s)
84	T1-31-7,8,10	<5E-9	.01	No	<5E-7	TW Sequence(s)
89	T1-36/S2-24-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T-36/S2-24-19,20,21,26, 27,28,33,34,35,40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T1-36/S2-27-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T1-36/S2-27-19,20,21, 26,27,28,33,34,35,40,41, 42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T1-36/S2-30-7,8,10,15, 16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T1-36/S2-33-7,8,10,15, 16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T1-36/S2-36-7,8,10,15, 16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
93	T1-40/S1-57,63,69	<1E-8	0.1	No	<1E-7	TW Sequence(s)
	T1-40/S1-76,82,88	<1E-8	0.1	No	<1E-7	TW Sequence(s)
97	T1-43/A-23,29	<1E-8	0.1	No	<1E-7	TW Sequence(s)
101	T2-4-9,10,12,28,29,30, 31	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T2-4-19,20,21,36,37,38 43,44,45,50,51,52	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T2-10-9,10,12,28,29,30, 31	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T2-10-19,20,21,36,37,38, 43,44,45,50,51,52	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T2-6-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T2-6-20,21,22,28,29,30, 36,37,38,44,45,46	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T2-12-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T2-12-20,21,22,28,29,30, 36,37,38,44,45,46	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T2-16-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T2-16-19,20,21	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T2-20-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T2-20-15,16,17	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T2-24-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	T2-24-15,16,17	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T2-28-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T2-28-15,16,17	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T2-33-14,15,16,21,22, 23,28,29,30	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T2-35-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T2-37/S2-4-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T2-37/S2-4-19,20,21,26, 27,28,33,34,35,40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T2-37/S2-7-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T2-37/S2-7-19,20,21,26, 27,28,33,34,35,40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T2-37/S2-10-9,10,12,19, 20,21	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T2-37/S2-13-7,8,10,15, 16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T2-37/S2-16-7,8,10,15, 16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary
Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	T2-37/S2-19-7,8,10,15, 16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T2-38/S1-8,16,24,33,41, 49	<1E-8	.1	No	<1E-7	TW Sequence(s)
	T2-39/A-8,16	<1E-8	.1	No	<1E-7	TW Sequence(s)
	T2-41/T1-4-7,8,10	<1E-8	1E-2	No	<1E-6	TW Sequence(s)
	T2-41/T1-4-15,16,17,22, 23,24,29,30,31	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T2-41/T1-6-7,8,10	<1E-8	1E-2	No	<1E-6	TW Sequence(s)
	T2-41/T1-6-16,17,18,24, 25,26,32,33,34	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T2-41/T1-10-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T2-41/T1-10-15,16,17,22, 23,24,29,30,31	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T2-41/T1-12-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T2-41/T1-12-16,17,18, 24,25,26,32,33,34	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T2-41/T1-16-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	T2-41/T1-16-15,16,17	<1E-9	.5	Yes	<2E-9	Sequence(s) below "cutoff" TW Sequence(s)
	T2-41/T1-20-7,8,10,15, 16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T2-41/T1-24-7,8,10	<1E-8	1E-2	No	<1E-6	TW Sequence(s)
	T2-41/T1-24-15,16,17	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T2-41/T1-29-5,6,7,12, 13,14	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T2-41/T1-29-19,20,21	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T2-41/T1-31-7,8,10	<5E-9	.01	No	<5E-7	TW Sequence(s)
	T2-41/T1-36/S2-24-9, 10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T2-41/T1-36/S2-24-19, 20,21,26,27,28,33,34, 35,40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T2-41/T1-36/S2-27-9, 10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T2-41/T1-36/S2-27-19, 20,21,26,27,28,33,34, 35,40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T2-41/T1-36/S2-30-7,8, 10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	T2-41/T1-36/S2-33-7,8, 10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T2-41/T1-36/S2-36-7,8, 10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T2-41/T1-40/S1-57,63, 69	<1E-8	.1	No	<1E-7	TW Sequence(s)
	T2-41/T1-40/S1-76,82, 88	<1E-8	.1	No	<1E-7	TW Sequence(s)
	T2-41/T1-43/A-23,29	<1E-8	.1	No	<1E-7	TW Sequence(s)
105	T3A-40/A-8,16	<6E-9	.1	No	<6E-8	TW Sequence(s)
	T3A-39/S1-8,16,24	<1E-8	.1	No	<1E-7	TW Sequence(s)
	T3A-38/S2-4-9,10,12	<1E-9	.01	No	<1E-7	TW Sequence(s)
	T3A-38/S2-4-19,20,21, 26,27,28,33,34,35,40, 41,42	<3E-9		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3A-38/S2-7-9,10,12	<3E-9	.01	No	<3E-7	TW Sequence(s)
	T3A-38/S2-7-19,20,21, 26,27,28,33,34,35,40, 41,42	<3E-9		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	T3A-38/S2-10-9,10,12, 19,20,21	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3A-38/S2-13-7,8,10, 15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3A-38/S2-16-7,8,10, 15,16,17	<1E-10		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3A-38/S2-19-7,8,10, 15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3A-/(T2-1)-4-9,10, 12,28,29,30,31	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3A-/(T2-1)-4-19,20,21, 36,37,38,43,44,45,50,51, 52	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3A-/(T2-1)-10-9,10, 12,28,29,30,31	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3A-/(T2-1)-10-19,20, 21,36,37,38,43,44,45,50, 51,52	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3A-/(T2-1)-6-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3A-/(T2-1)-6-20,21,22, 28,29,30,36,37,38,44,45, 46	<1E-8	.5	No	<2E-8	TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	T3A-/(T2-1)-12-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3A-/(T2-1)-12-20,21,22, 28,29,30,36,37,38,44,45, 46	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3A-/(T2-1)-16-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3A-/(T2-1)-16-19,20,21	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3A-/(T2-1)-20-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	(T3A-/(T2-1)-20-15,16,17	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3A-/(T2-1)-24-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3A-/(T2-1)-24-15,16,17	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3A-/(T2-1)-28-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3A-/(T2-1)-28-15,16,17	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3A-/(T2-1)-33-14,15, 16,21,22,23,28,29,30	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3A-/(T2-1)-35-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3A-42/T1-4-7,8,10	<1E-8	1E-2	No	<1E-6	TW Sequence(s)
	T3A-42/T1-4-15,16,17, 22,23,24,29,30,31	<5E-9	.5	Yes	<1E-8	Sequence(s) below "cutoff" TW Sequence(s)
	T3A-42/T1-6-7,8,10	<1E-8	1E-2	No	<1E-6	TW Sequence(s)
	T3A-42/T1-6-16,17,18, 24,25,26,32,33,34	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	T3A-42/T1-10-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3A-42/T1-10-15,16,17, 22,23,24,29,30,31	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3A-42/T1-12-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3A-42/T1-12-16,17,18, 24,25,26,32,33,34	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3A-42/T1-16-7,8,10	<1E-9	.01	No	<1E-7	TW Sequence(s)
	T3A-42/T1-16-15,16,17	<1E-9	.5	Yes	<2E-9	Sequence(s) below "cutoff" TW Sequence(s)
	T3A-42/T1-20-7,8,10,15, 16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3A-42/T1-24-7,8,10	<1E-8	1E-2	No	<1E-6	TW Sequence(s)
	T3A-42/T1-24-15,16,17	<1E-9	.5	Yes	<2E-9	Sequence(s) below "cutoff" TW Sequence(s)
	T3A-42/T1-29-5,6,7	<1E-10	.01	Yes	<1E-8	Sequence(s) below "cutoff" TW Sequence(s)
	T3A-42/T1-29-12,13,14	<1E-10	.01	Yes	<1E-8	Sequence(s) below "cutoff" TW Sequence(s)
	T3A-42/T1-29-19,20,21	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3A-42/T1-31-7,8,10	<5E-9	.01	No	<5E-7	TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	T3A-42/T1-36/S2-24-9, 10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3A-42/T1-36/S2-24-19, 20,21,26,27,28,33,34, 35,40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3A-42/T1-36/S2-27-9, 10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3A-42/T1-36/S2-27-19, 20,21,26,27,28,33,34, 35,40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3A-42/T1-36/S2-30-7, 8,10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3A-42/T1-36/S2-33-7, 8,10,15.16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3A-42/T1-36/S2-36-7, 8,10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3A-42/T1-40/S1-57,63,69	<1E-8	.1	No	<1E-7	TW Sequence(s)
	T3A-42/T1-40/S1-76,82,88	<1E-8	.1	No	<1E-7	TW Sequence(s)
	T3A-42/T1-43/A-23,29	<1E-8	.1	No	<1E-7	TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
106	T3B-1/T2-4-9,10,12,28, 29,30,31	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3B-1/T2-4-19,20,21,36, 37,38,43,44,45,50,51,52	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3B-1/T2-10-9,10,12,28, 29,30,31	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3B-1/T2-10-19,20,21,36, 37,38,43,44,45,50,51,52	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3B-1/T2-6-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3B-1/T2-6-20,21,22,28, 29,30,36,37,38,44,45,46	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3B-1/T2-12-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3B-1/T2-12-20,21,22,28, 29,30,36,37,38,44,45,46	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3B-1/T2-16-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3B-1/T2-16-19,20,21	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3B-1/T2-20-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3B-1/T2-20-15,16,17	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3B-1/T2-24-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3B-1/T2-24-15,16,17	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3B-1/T2-28-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3B-1/T2-28-15,16,17	<1E-8	.5	No	<2E-8	TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	T3B-1/T2-33-14,15,16, 21,22,23,28,29,30	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3B-1/T2-35-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3B-1/T2-37/S2-4-9,10, 12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3B-1/T2-37/S2-4-19,20, 21,26,27,28,33,34,35,40, 41,42	<1E-8		Yes	<1E-8	Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3B-1/T2-37/S2-7-9,10, 12	<1E-8	.1	No	<1E-7	TW Sequence(s)
	T3B-1/T2-37/S2-7-19,20, 21,26,27,28,33,34,35,40, 41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3B-1/T2-37/S2-10-9,10, 12,19,20,21	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3B-1/T2-37/S2-13-7,8, 10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3B-1/T2-37/S2-16-7,8, 10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	T3B-1/T2-37/S2-19-7,8, 10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3B-1/T2-38/S1-8,16,24, 33,41,49	<1E-8	.1	No	<1E-7	TW Sequence(s)
	T3B-1/T2-39/A-8,16	<1E-8	.1	No	<1E-7	TW Sequence(s)
	T3B-1/T2-41/T1-4-7,8, 10	<1E-8	1E-2	No	<1E-6	TW Sequence(s)
	T3B-1/T2-41/T1-4-15,16, 17,22,23,24,29,30,31	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3B-1/T2-41/T1-6-7,8, 10	<1E-8	1E-2	No	<1E-6	TW Sequence(s)
	T3B-1/T2-41/T1-6-16,17, 18,24,25,26,32,33,34	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3B-1/T2-41/T1-10-7,8, 10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3B-1/T2-41/T1-10-15,16, 17,22,23,24,29,30,31	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3B-1/T2-41/T1-12-7,8, 10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3B-1/T2-41/T1-12-16, 17,18,24,25,26,32,33,34	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary
Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	T3B-1/T2-41/T1-16-7,8, 10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3B-1/T2-41/T1-16-15, 16,17	<1E-9	.5	Yes	<5E-9	Sequence(s) below "cutoff" TW Sequence(s)
	T3B-1/T2-41/T1-20-7,8, 10,15,16,17	<1E-8		Yes		(Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3B-1/T2-41/T1-24-7, 8,10	<1E-8	1E-2	No	<1E-6	TW Sequence(s)
	T3B-1/T2-41/T1-24-15, 16,17	<1E-8	.5	No	<5E-8	TW Sequence(s)
	T3B-1/T2-41/T1-29-5,6, 7,12,13,14	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3B-1/T2-41/T1-29-19, 20,21	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3B-1/T2-41/T1-31-7,8, 10	<5E-9	.01	No	<5E-7	TW Sequence(s)
	T3B-1/T2-41/T1-36/S2-24-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3B-1/T2-41/T1-36/S2-24-19,20,21,26,27,28,33, 34,35,40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3B-1/T2-41/T1-36/S2-27-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	T3B-1/T2-41/T1-36/S2-27-19,20,21,26,27,28,33,34,35,40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3B-1/T2-41/T1-36/S2-30-7,8,10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3B-1/T2-41/T1-36/S2-33-7,8,10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3B-1/T2-41/T1-36/S2-36-7,8,10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3B-1/T2-41/T1-40/S1-57,63,69	<1E-8	.1	No	<1E-7	TW Sequence(s)
	T3B-1/T2-41/T1-40/S1-76,82,88	<1E-8	.1	No	<1E-7	TW Sequence(s)
	T3B-1/T2-41/T1-43/A-23,29	<1E-8	.1	No	<1E-7	TW Sequence(s)
107	T3C-2/S2-4-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3C-2/S2-4-19,20,21,26,27,28,33,34,35,40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3C-2/S2-7-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	T3C-2/S2-7-19,20,21,26, 27,28,33,34,35,40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3C-2/S2-10-9,10,12,19, 20,21	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3C-2/S2-13-7,8,10,15, 16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3C-2/S2-16-7,8,10,15, 16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3C-2/S2-19-7,8,10,15, 16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3C-3/T1-4-7,8,10	<1E-8	1E-2	No	<1E-6	TW Sequence(s)
	T3C-3/T1-4-15,16,17,22, 23,24,29,30,31	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3C-3/T1-6-7,8,10	<1E-8	1E-2	No	<1E-6	TW Sequence(s)
	T3C-3/T1-6-16,17,18,24, 25,26,32,33,34	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	T3C-3/T1-10-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3C-3/T1-10-15,16,17,22, 23,24,29,30,31	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3C-3/T1-12-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3C-3/T1-12-16,17,18, 24,25,26,32,33,34	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3C-3/T1-16-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3C-3/T1-16-15,16,17	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3C-3/T1-20-7,8,10,15, 16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3C-3/T1-24-7,8,10	<1E-8	1E-2	No	E-6	TW Sequence(s)
	T3C-3/T1-24-15,16,17	<1E-8	.5	No	<2E-8	TW Sequence(s)
	T3C-3/T1-29-5,6,7	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3C-3/T1-29-12,13,14	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3C-3/T1-31-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3C-3/T1-36/S2-24-9, 10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3C-3/T1-36/S2-24-19, 20,21,26,27,28,33,34,35, 40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	T3C-3/T1-36/S2-27-9, 10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	T3C-3/T1-36/S2-27-19, 20,21,26,27,28,33,34,35, 40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3C-3/T1-36/S2-30-7,8, 10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3C-3/T1-36/S2-33-7,8, 10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3C-3/T1-36/S2-36-7,8, 10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	T3C-3/T1-40/S1-57,63, 69	<1E-8	.1	No	<1E-7	TW Sequence(s)
	T3C-3/T1-40/S1-76,82, 88	<1E-8	.1	No	<1E-7	TW Sequence(s)
	T3C-3/T1-43/A-23,29	<1E-8	.1	No	<1E-7	TW Sequence(s)
108	S3-1/T3A-40/A-8,16	<1E-8	.1	No	<1E-7	
	S3-1/T3A-39/S1-8,16,24	<1E-8	.1	No	<1E-7	
	S3-T3A-38/S2-4-9,10,12	<1E-8	.01	No	<1E-6	

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary
Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	S3-1/T3A-38/S2-4-19, 20,21,26,27,28,33,34, 35,40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated
	S3-1/T3A-38/S2-7-9,10, 12	<1E-8	.01	No	<1E-6	
	S3-1/T3A-38/S2-7-9,20, 21,26,27,28,33,34,35,40, 41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated
	S3-1/T3A-38/S2-10-9,10, 12,19,20,21	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated
	S3-1/T3A-38/S2-13-7,8, 10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated
	S3-1/T3A-38/S2-16-7,8, 10,15,16	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated
	S3-1/T3A-38/S2-19-7,8, 10,15,16	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated
	S3-1/T3A/(T2-1)-4-9, 10,12,28,29,30,31	<1E-8	.01	No	<1E-6	
	S3-1/T3A/(T2-1)-4-19,20, 21,36,37,38,43,44,45,50, 51,52	<1E-8	.5	No	<2E-8	
	S3-1/T3A/(T2-1)-10-9, 10,12,28,29,30,31	<1E-8	.01	No	<1E-6	

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	S3-1/T3A/(T2-1)-10-19, 20,21,36,37,38,43,44,45, 50,51,52	<1E-8	.5	No	<2E-8	
	S3-1/T3A/(T2-1)-6-9, 10,12	<1E-8	.01	No	<1E-6	
	S3-1/T3A/(T2-1)-6-20,21, 22,28,29,30,36,37,38,44, 45,46	<1E-8	.5	No	<2E-8	
	S3-1/T3A/(T2-1)-12-9, 10,12	<1E-8	.01	No	<1E-6	
	S3-1/T3A/(T2-1)-12-20, 21,22,28,29,30,36,37,38, 44,45,46	<1E-8	.5	No	<2E-8	
	S3-1/T3A/(T2-1)-16-9, 10,12	<1E-8	.01	No	<1E-6	
	S3-1/T3A/(T2-1)-16-19, 20,21	<1E-8	.5	No	<2E-8	
	S3-1/T3A/(T2-1)-20-7, 8,10	<1E-8	.01	No	<1E-6	
	S3-1/T3A/(T2-1)-20-15, 16,17	<1E-8	.5	No	<2E-8	
	S3-1/T3A/(T2-1)-24-7, 8,10	<1E-8	.01	No	<1E-6	
	S3-1/T3A/(T2-1)-24-15, 16,17	<1E-8	.5	No	<2E-8	

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	S3-1/T3A/(T2-1)-28-7, 8,10	<1E-8	.01	No	<1E-6	
	S3-1/T3A/(T2-1)-28-15, 16,17	<1E-8	.5	No	<2E-8	
	S3-1/T3A/(T2-1)-33-14, 15,16,21,22,23,28,29,30	<1E-8	.01	No	<1E-6	
	S3-1/T3A/(T2-1)-35-9, 10,12	<1E-8	.01	No	<1E-6	
	S3-1/T3A-42/T1-4-7,8, 10	<1E-8	1E-2	No	<1E-6	
	S3-1/T3A-42/T1-4-15,16, 17,22,23,24,29,30,31	<1E-8	.5	No	<2E-8	
	S3-1/T3A-42/T1-6-7,8, 10	<1E-8	.01	No	<1E-6	
	S3-1/T3A-42/T1-6-16,17, 18,24,25,26,32,33,34	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated
	S3-1/T3A-42/T1-10-7,8, 10	<1E-8	.01	No	<1E-6	
	S3-1/T3A-42/T1-10-15,16, 17,22,23,24,29,30,31	<1E-8	.5	No	<2E-8	
	S3-1/T3A-42/T1-12-7,8, 10	<1E-8	.01	No	<1E-6	
	S3-1/T3A-42/T1-12-16, 17,18,24,26,32,33,34	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	S3-1/T3A-42/T1-16-7, 8,10	<1E-8	.01	No	<1E-6	
	S3-1/T3A-42/T1-16-15, 16,17	<1E-8	.5	No	<2E-8	
	S3-1/T3A-42/T1-20-7,8, 10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated
	S3-1/T3A-42/T1-24-7,8, 10	<1E-8	1E-2	No	<1E-6	
	S3-1/T3A-42/T1-24-15, 16,17	<1E-8	.5	No	<2E-8	
	S3-1/T3A-42/T1-29-5, 6,7	<1E-8	.01	No	<1E-6	
	S3-1/T3A-42/T1-29-12, 13,14	<1E-8	.01	No	<1E-6	
	S3-1/T3A-42/T1-29-19, 20,21	<1E-8	.01	No	<1E-6	
	S3-1/T3A-42/T1-31-7, 8,10	<1E-8	.01	No	<1E-6	
	S3-1/T3A-42/T1-36/S2-24-9,10,12	<1E-8	.01	No	<1E-6	
	S3-1/T3A-42/T1-36/S2-24-19,20,21,26,27,28, 33,34,35,40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated
	S3-1/T3A-42/T1-36/S2-27-9,10,12	<1E-8	.01	No	<1E-6	

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	S3-1/T3A-42/T1-36/S2-27-19,20,21,26,27,28,33,34,35,40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated
	S3-1/T3A-42/T1-36/S2-30-7,8,10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated
	S3-1/T3A-42/T1-36/S2-33-7,8,10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated
	S3-1/T3A-42/T1-36/S2-36-7,8,10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated
	S3-1/T3A-42/T1-40/S1-57,63,69	<1E-8	.1	No	<1E-7	
	S3-1/T3A-42/T1-40/S1-76,82,88	<1E-8	.1	No	<1E-7	
	S3-1/T3A-42/T1-43/A-23,29	<1E-8	.1	No	<1E-7	
109	TAC/DC-4,10-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	TAC/DC-4,10-15,16,17,22,23,24,29,30,31	<1E-8	.5	No	<2E-8	TW Sequence(s)
	TAC/DC-6,12-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	TAC/DC-6,12-16,17,18,24,25,26,32,33,34	<1E-8	.5	No	<2E-8	TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	TAC/DC-16,20,24-7,8, 9,10	<1E-8	.01	No	<1E-8	TW Sequence(s)
	TAC/DC-16,20,24-15,16	<1E-8	.5	No	<2E-8	TW Sequence(s)
	TAC/DC-29-15,16,17,22, 23,24,29,30,31	<1E-8	.01	No	<1E-6	TW Sequence(s)
	TAC/DC-31-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	TAC/DC-33/S2-4-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	TAC/DC-33/S2-4-19,20, 21,26,27,28,33,34,35, 40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	TAC/DC-33/S2-7-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	TAC/DC-33/S2-7-19,20, 21,26,27,28,33,34,35, 40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	TAC/DC-33/S2-10-9,10, 12,19,20,21	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	TAC/DC-33/S2-13-7,8, 10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	TAC/DC-33/S2-16-7,8,10, 15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary
Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	TAC/DC-33/S2-19-7,8,10, 15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	TAC/DC-33/S2-24-9,10, 12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	TAC/DC-33/S2-24-19,20, 21,26,27,28,33,34,35,40, 41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	TAC/DC-33-S2-27-9,10, 12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	TAC/DC-33/S2-27-19,20, 21,26,27,28,33,34,35,40, 41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	TAC/DC-33/S2-30-7,8,10, 15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	TAC/DC-33/S2-33-7,8,10, 15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	TAC/DC-33/S2-36-7,8,10, 15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	TAC/DC-34/S1-8,16,24	<1E-8	.1	No	<1E-7	TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Vènting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	TAC/DC-35/A-8,16	<1E-8	.1	No	<1E-7	TW Sequence(s)
	TAC/DC-37/T1-4-7,8,10	<1E-8	1E-2	No	<1E-6	TW Sequence(s)
	TAC/DC-37/T1-4-15,16, 17,22,23,24,29,30,31	<1E-8	.5	No	<2E-8	TW Sequence(s)
	TAC/DC-37/T1-6-7,8,10	<1E-8	1E-2	No	<1E-6	TW Sequence(s)
	TAC/DC-37/T1-6-16,17, 18,24,25,26,32,33,34	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	TAC/DC-37/T1-10-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	TAC/DC-37/T1-10-15,16, 17,22,23,24,29,30,31	<1E-8	.5	No	<2E-8	TW Sequence(s)
	TAC/DC-37/T1-12-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	TAC/DC-37/T1-12-16,17, 18,24,25,26,32,33,34	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	TAC/DC-37/T1-16-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	TAC/DC-37/T1-16-15,16, 17	<1E-8	.5	No	<2E-8	TW Sequence(s)
	TAC/DC-37/T1-20-7,8,10, 15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4.10-1)[1] without PCV and eliminated TW Sequence(s)
	TAC/DC-37/T1-24-7,8,10	<1E-8	1E-2	No	<1E-6	TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary
Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	TAC/DC-37/T1-24-15,16, 17	<1E-8	.5	No	<2E-8	TW Sequence(s)
	TAC/DC-37/T1-29-5,6,7	<1E-8	.01	No	<1E-6	TW Sequence(s)
	TAC/DC-37/T1-29-12,13, 14	<1E-8	.01	No	<1E-6	TW Sequence(s)
	TAC/DC-37/T1-29-19,20, 21	<1E-8	.01	No	<1E-6	TW Sequence(s)
	TAC/DC-37/T1-31-7,8,10	<1E-8	.01	No	<1E-6	TW Sequence(s)
	TAC/DC-37/T1-36/S2-24-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	TAC/DC-37/T1-36/S2-24-19,20,21,26,27,28,33,34, 35,40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4-10-1)[1] without PCV and eliminated TW Sequence(s)
	TAC/DC-37/T1-36/S2-27-9,10,12	<1E-8	.01	No	<1E-6	TW Sequence(s)
	TAC/DC-37/T1-36/S2-27-19,20,21,26,27,28,33,34, 35,40,41,42	<1E-8		Yes		Sequence(s) previously quantified Table 4-10-1)[1] without PCV and eliminated TW Sequence(s)
	TAC/DC-37/T1-36/S2-30-7,8,10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4-10-1)[1] without PCV and eliminated TW Sequence(s)
	TAC/DC-37/T1-36/S2-33-7,8,10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4-10-1)[1] without PCV and eliminated TW Sequence(s)

TABLE 3.7 (Continued)

Non-Dominant Sequences Quantified with Primary Containment Venting System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "Y" Value Used	Sequence Eliminated	Estimate Frequency With "Y" Unavailable	Comments
	TAC/DC-37/T1-36/S2-36-7,8,10,15,16,17	<1E-8		Yes		Sequence(s) previously quantified Table 4-10-1)[1] without PCV and eliminated TW Sequence(s)
	TAC/DC-37/T1-40/S1-57, 63,69	<1E-8	.1	No	<1E-7	TW Sequence(s)
	TAC/DC-37/T1-40/S1-76, 82,88	<1E-8	.1	No	<1E-7	TW Sequence(s)
	TAC/DC-37/T1-43/A-23, 29	<1E-8	.1	No	<1E-7	TW Sequence(s)

Table 3.8 contains a list of the estimated frequencies for sequences without the PCV system. These are listed by their associated initiating event. Recovery can be applied to the S2, S3, T1, T2, T3A, T3B, T3C and TAC/DC events. The recovery action applied was PCSNR13HR (probability of 1.0E-2), which denotes recovery of the Power Conversion System (PCS) within 13 hours. Successful recovery implies heat removal to the PCS, which removes it to the ultimate heat sink. The core is cooled and the containment pressure and temperature are no longer rising. The PCS is of no use to sequences with initiating events A and S1, since heat is escaping out the break into the containment.

Adding the total frequency of 5.65E-6 from Table 3.8 to the previous point estimate of 3.62E-6 yields a value of 9.27E-5, an increase of a factor of ~2.6. While this is not a large increase in the point estimate of the plant, it does indicate a change in perspective for the plant. The results of this analysis are extremely plant specific, depending on the piping configuration and emergency procedures. Also, the analysis does not consider any possible negative effects from venting due to fission product releases as a result of unnecessary venting.

Table 3.8

Estimated Sequence Frequencies without PCV

Initiating Event	Estimated CDF Without Recovery	Estimated CDF With Recovery
A-	<1.2E-7	<1.2E-7
S1-	<6.0E-7	<6.0E-7
S2-	<7.2E-6	<7.2E-8
S3-1-	<8.88E-5	<8.88E-7
T1-	<2.68E-5	<2.68E-7
T2-	<8.47E-5	<8.47E-7
T3A-	<7.36E-5	<7.36E-7
T3B-	<8.51E-5	<8.51E-7
T3C-	<4.01E-5	<4.01E-7
TAC/DC-	<8.64E-5	<8.64E-7
Total	<4.93E-4	<5.65E-6
LOCAs	<9.672E-5	<1.68E-6
TWs	<3.967E-4	<3.97E-6

Total point estimate from NUREG/CR-4550 [6] is 3.62E-6.

3.3.2 High Pressure Service Water Injection

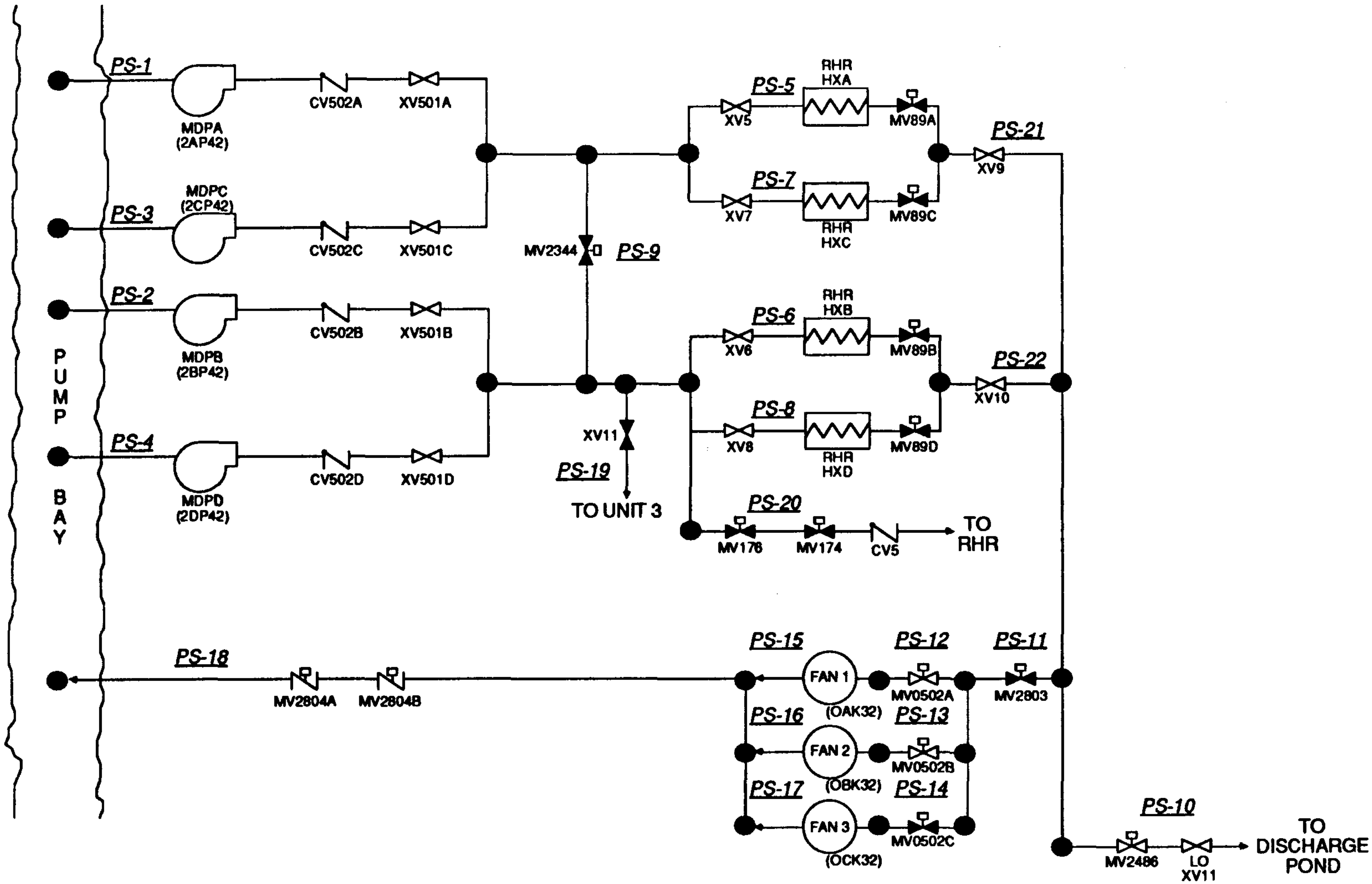
The High Pressure Service Water (HPSW) system can be used as a Phase 2 option to provide an alternate source of cooling water during a variety of accident sequences at Peach Bottom. The sequences affected are typically those in which some dependent failure has occurred that affects multiple safety systems. Since the HPSW components are located mostly outside containment and it takes suction from the river, the system is not affected by those dependent failures. Thus, it provides diversity as well as redundancy. The drawback of using this system is that it injects river water into the reactor which requires extensive cleanup after this type of use.

The HPSW injection is accomplished via a cross-tie to the Residual Heat Removal (RHR) injection lines (event tree nomenclature -"V_4"). A simplified schematic of the HPSW system is provided by Figure 3.1. As an injection source to the reactor vessel, the HPSW discharge to the RHR injection lines is from the B/D pump header which connects to the RHR header. To inject water into the reactor vessel via the RHR system, the operator starts HPSW pumps B and/or D and opens MOV-176 and MOV-174. Pump B or D must supply flow through the cross-tie and corresponding RHR injection line under depressurized conditions in the reactor vessel. Despite its name, the HPSW is a low pressure system relative to the high pressure injection systems at Peach Bottom. Pumps A or C can be used with operation of a cross tie valve. The system depends on AC power and manual actuation for success.

To determine the significance HPSW has had on the Peach Bottom analysis, the solution to the HPSW fault tree obtained from a SETS analysis in Reference 6 was reviewed. The dominant system cut set consists of the single event ESF-XHE-FO-HSWIN. This cut set represents a failure of the operator to realign HPSW for injection and accounts for 82% of the unavailability of the HPSW system in this analysis.

There was one plant damage state in the NUREG-1150 analysis which contained HPSW injection. This plant damage state contained cut sets from the dominant sequences, as described in Reference 6. Only the sequences which appeared to have frequency estimates greater than 1E-8 were completely analyzed in Reference 6. The technique chosen to eliminate the HPSW system from these sequences (and their corresponding plant damage states) was to set the probability of the basic event, ESW-XHE-FO-HSWIN, to 1.0, which ensures HPSW injection failure. This is an approximation which neglects the small amount of double counting of cut sets (<18%) that is possible with this method.

One plant damage state (PDS-03) and the total plant were requantified using the TEMAC computer code. A detailed description of the plant



VALVE POSITIONS ARE SHOWN IN THEIR STANDBY MODE

Figure 3.1. High Pressure Service Water System Schematic.

damage states can be found in Section 4.11 of Reference 6. Table 3.9 compares the estimated frequencies from NUREG-1150 to those which have been requantified. Although an increase of a factor of 4 is realized for PDS-03, the total plant calculation shows only a slight increase. For the NUREG-1150 dominant sequences, the HPSW system does not have a significant influence on the total plant core damage frequency.

To determine the significance HPSW availability or unavailability has on the previously non-dominant sequences, all of the event trees from Reference 6 were reviewed. The success branches for HPSW were ignored since they do not exist if HPSW is removed from the tree. All of the non-dominant sequence failure branches were traced and approximately 900 sequences containing HPSW were found that previously were screened out in the Ref. 6 analysis.

Table 3.9

Estimated Plant Damage State Frequencies without HPSW

PDS	Description	NUREG-1150 Estimated CDF	New Estimated CDF
PDS-03	Transient with Loss of Low Pressure Injection Systems and Two Stuck Open Relief Valves	5.83E-9	2.33E-8
Total Plant		3.62E-6	3.64E-6

These 900 sequences were requantified with the HPSW system eliminated from the event tree. Some of these sequences with frequencies below 1E-8 were previously screened out (see Table 4.10-1 of Reference 6) without using the "V_4" event failure and were subsequently eliminated from this requantification. This left approximately 150 sequences.

Table 3.10 is a compilation of these sequences listing the accident sequence numbers, estimated frequencies and the approximate "V_4" event probabilities assigned to each sequence from Table 4.10-1 of Reference 6. Table 3.10 also lists the corresponding event tree sequences, new estimated frequencies, and relevant comments and indicates whether or not the sequence could be screened out.

To determine the new estimated sequence frequencies, previously estimated sequence frequencies were divided by the appropriate "V_4" event probabilities used in the 1150 analysis. Some of the "V_4" values used in

(text continued on page 3-62)

Table 3.10

Non-Dominant Sequences Quantified
with HPSW System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "V_4" Value Used	Sequence Eliminated	Estimate Frequency With "V_4" Unavailable	Comments
1	A-5	<6E-9	6E-2	No	<1.0E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
3	A-13	<6E-9	6E-2	No	1.0E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
6	A-21,27	<1E-9	6E-2	No	<1.7E-8	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
8	S1-5	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
10	S1-13	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
15	S1-30,38	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
16	S1-50	<7E-9	.1	No	<7E-8	"V_4" value given in Table 4.10-1[1]
18	S1-55,61	<1E-9	6E-2	No	<1.7E-8	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
19	S1-70	<1E-9	.1	Yes	<1.0E-8	V-type sequence, Type 4 from Table Three
20	S1-74,80	<1E-9	6E-2	No	<1.7E-8	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
	S1-89	<1E-9	.1	Yes	<1.0E-8	V-type sequence, Type 4 from Table Three
24	S2-4-4	<1E-10	6E-2	Yes	<1.7E-9	"Y" has succeeded, W-type sequence, Type 4 from Table Three

TABLE 3.10 (Cont.)

Non-Dominant Sequences Quantified
with HPSW System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "V_4" Value Used	Sequence Eliminated	Estimate Frequency With "V_4" Unavailable	Comments
30	S2-7-4	<3E-9	6E-2	No	<5.0E-8	"Y" has succeeded, W-type sequence, Type 4 from Table Three
35	S2-20	<1E-9	2.5E-2	No	<4.0E-8	V-type sequence, Type 3 from Table Three
38	S2-24-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
40	S2-27-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
44	S2-37	<1E-8	2.5E-2	No	<4.0E-7	V-type sequence, Type 3 from Table Three
47	S3-2/S2-4-4	<1E-9	6E-2	No	<1.7E-8	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	S3-2/S2-7-4	<1E-9	6E-2	No	<1.7E-8	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	S3-2/S2-20	<1E-9	2.5E-2	No	<4.0E-8	V-type sequence, Type 3 from Table Three
	S3-2/S2-24-4	<1E-9	6E-2	No	<1.7E-8	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	S3-2/S2-27-4	<1E-9	6E-2	No	<1.7E-8	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	S3-2/S2-37	<1E-9	2.5E-2	No	<4.0E-8	V-type sequence, Type 3 from Table Three
49	T1-3-5	<1E-10	6E-2	Yes	<1.7E-9	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
54	T1-4-32	<1E-10	6E-2	Yes	<1.7E-9	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism

TABLE 3.10 (Cont.)

Non-Dominant Sequences Quantified
with HPSW System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "V_4" Value Used	Sequence Eliminated	Estimate Frequency With "V_4" Unavailable	Comments
60	T1-9-5	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
61	T1-10-32	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
73	T1-25	<1E-8	.1	No	<1E-7	"V_4" value given in Table 4.10-1[1]
74	T1-27-4	<1E-10	6E-2	Yes	<1.7E-9	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
75	T1-28-4	<1E-10	6E-2	Yes	<1.7E-9	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
82	T1-29-22	<5E-9	6E-2	No	<8.3E-8	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
89	T1-36/S2-4-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T1-36/S2-7-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T1-36/S2-20	<1E-8	2.5E-2	No	<4.0E-7	V-type sequence, Type 3 from Table Three
	T1-36/S2-24-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T1-36/S2-27-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T1-36/S2-37	<1E-8	2.5E-2	No	<4.0E-7	V-type sequence, Type 3 from Table Three
93	T1-40/S1-55,61	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.

TABLE 3.10 (Cont.)

Non-Dominant Sequences Quantified
with HPSW System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "V_4" Value Used	Sequence Eliminated	Estimate Frequency With "V_4" Unavailable	Comments
	T1-40/S1-70	<1E-8	.1	No	<1E-7	V-type sequence, Type 4 from Table Three
	T1-40/S1-74,80	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
	T1-40/S1-89	<1E-8	.1	No	<1E-7	V-type sequence, Type 4 from Table Three
97	T1-43/A-21,27	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
101	T2-37/S2-4-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T2-37/S2-7-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T2-37/S2-20	<1E-8	2.5E-2	No	<4.0E-7	V-type sequence, Type 3 from Table Three
105	T3A-38/S2-4-4	<1E-10	6E-2	Yes	<1.7E-9	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T3A-38/S2-7-4	<1E-9	6E-2	No	<1.7E-8	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T3A-38/S2-20	<1E-9	2.5E-2	No	<4.0E-8	V-type sequence, Type 3 from Table Three
	T3A-39/S1-5,13	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
	T3A-39/S1-30,38	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.

TABLE 3.10 (Cont.)

Non-Dominant Sequences Quantified
with HPSW System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "V_4" Value Used	Sequence Eliminated	Estimate Frequency With "V_4" Unavailable	Comments
	T3A-39/S1-50	<7E-9	.1	No	<7E-8	"V_4" value given in Table 4.10-1[1]
	T3A-40/A-5,13	<6E-9	.01	No	<6E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
	T3A-42/T1-3-5	<1E-10	6E-2	Yes	<1.7E-9	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	T3A-42/T1-4-32	<1E-10	6E-2	Yes	<1.7E-9	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	T3A-42/T1-9-5	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	T3A-42/T1-10-32	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	T3A-42/T1-25	<1E-8	.1	No	<1E-7	"V_4" value given in Table 4.10-1[1]
	T3A-42/T1-27-4	<1E-10	6E-2	Yes	<1.7E-9	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	T3A-42/T1-28-4	<1E-10	6E-2	Yes	<1.7E-9	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	T3A-42/T1-29-22	<5E-9	6E-2	No	<8.3E-8	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	T3A-42/T1-36/S2-4-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T3A-42/T1-36/S2-7-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three

TABLE 3.10 (Cont.)

Non-Dominant Sequences Quantified with HPSW System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "V_4" Value Used	Sequence Eliminated	Estimate Frequency With "V_4" Unavailable	Comments
	T3A-42/T1-36/S2-20	<1E-9	2.5E-2	No	<4.0E-7	V-type sequence, Type 3 from Table Three
	T3A-42/T1-36/S2-27-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T3A-42/T1-36/S2-24-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T3A-42/T1-36/S2-37	<1E-8	2.5E-2	No	<4.0E-7	V-type sequence, Type 3 from Table Three
	T3A-42/T1-40/S1-55,61	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
	T3A-42/T1-40/S1-74,80	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
	T3A-42/T1-89	<1E-8	.1	No	<1E-7	V-type sequence, Type 4 from Table Three
	T3A-42/T1-43/A-21,27	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
106	T3B-1/T2-37/S2-4-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T3B-1/T2-37/S2-7-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T3B-1/T2-37/S2-20	<1E-8	2.5E-2	No	<4.0E-7	V-type sequence, Type 3 from Table Three
107	T3C-2/S2-4-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three

TABLE 3.10 (Cont.)

Non-Dominant Sequences Quantified
with HPSW System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "V_4" Value Used	Sequence Eliminated	Estimate Frequency With "V_4" Unavailable	Comments
	T3C-2/S2-7-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T3C-2/S2-20	<1E-8	2.5E-2	No	<4.0E-7	V-type sequence, Type 3 from Table Three
	T3C-3/T1-3-5	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	T3C-3/T1-4-32	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	T3C-3/T1-9-5	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	T3C-3/T1-10-32	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	T3C-3/T1-25	<1E-8	.1	No	<1E-7	"V_4" value given in Table 4.10-1[1]
	T3C-3/T-27-4	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	T3C-3/T1-28-4	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	T3C-3/T1-29-22	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	T3C-3/T1-36/S2-4-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T3C-3/T1-36/S2-7-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T3C-3/T1-36/S2-20	<1E-8	2.5E-2	No	<4.0E-7	V-type sequence, Type 3 from Table Three

TABLE 3.10 (Cont.)

Non-Dominant Sequences Quantified with HPSW System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "V_4" Value Used	Sequence Eliminated	Estimate Frequency With "V_4" Unavailable	Comments
	T3C-3/T1-36/S2-27-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T3C-3/T1-36/S2-24-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	T3C-3/T1-36/S2-37	<1E-8	2.5E-2	No	<4.0E-7	V-type sequence, Type 3 from Table Three
	T3C-3/T1-40/S1-55,61	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
	T3C-3/T1-40/S1-74,80	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
	T3C-3/T1-40/S1-89	<1E-8	.1	No	<1E-7	V-type sequence, Type 4 from Table Three
	T3C-3/T1-43/A-21,27	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
108	S3-1/T3A-42/T1-40/S1-55,61	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
	S3-1/T3A-42/T1-40/S1-74,80	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
	S3-1/T3A-42/T1-40/S1-89	<1E-8	.1	No	<1E-7	V-type sequence, Type 4 from Table Three

TABLE 3.10 (Cont.)

Non-Dominant Sequences Quantified
with HPSW System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "V_4" Value Used	Sequence Eliminated	Estimate Frequency With "V_4" Unavailable	Comments
	S3-1/T3A-42/T1-43/A-21,27	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
109	TAC/DC-25	<1E-8	2.5E-2	No	<4.0E-7	V-type sequence, Type 3 from Table Three
	TAC/DC-33/S2-4-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	TAC/DC-33/S2-7-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	TAC/DC-33/S2-20	<1E-8	2.5E-2	No	<4.0E-7	V-type sequence, Type 3 from Table Three
	TAC/DC-35/A-5,13	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
	TAC/DC-35/A-21,27	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
	TAC/DC-34/S1-5,13,30,38	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
	TAC/DC-34/S1-50	<1E-8	.1	No	<1E-7	"V_4" value given in Table 4.10-1[1]
	TAC/DC-34/S1-55,61,74,80	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.
	TAC/DC-34/S1-70,89	<1E-8	.1	No	<1E-7	V-type sequence, Type 4 from Table Three. Values apply for each event tree sequence; they are not a total of all event tree sequences listed.

TABLE 3.10 (Cont.)

Non-Dominant Sequences Quantified
with HPSW System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "V_4" Value Used	Sequence Eliminated	Estimate Frequency With "V_4" Unavailable	Comments
	TAC/DC-37/T1-3-5	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	TAC/DC-37/T1-4-32	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	TAC/DC-37/T1-9-5	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	TAC/DC-37/T1-10-32	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	TAC/DC-37/T1-25	<1E-8	.1	No	<1E-7	"V_4" value given in Table 4.10-1[1]
	TAC/DC-37/T1-27-4	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	TAC/DC-37/T1-28-4	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	TAC/DC-37/T1-29-22	<1E-8	6E-2	No	<1.7E-7	Long term V-type sequence, use Type 4 from Table Three for W-type sequence for conservatism
	TAC/DC-37/T1-36/S2-4-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	TAC/DC-37/T1-36/S2-7-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	TAC/DC-37/T1-36/S2-20	<1E-8	2.5E-2	No	<4.0E-7	V-type sequence, Type 3 from Table Three
	TAC/DC-37/T1-36/S2-27-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three

TABLE 3.10 (Cont.)

Non-Dominant Sequences Quantified
with HPSW System Unavailable

Accident Sequence	Event Tree Sequence	Previously Estimated Frequency	Approximate "V_4" Value Used	Sequence Eliminated	Estimate Frequency With "V_4" Unavailable	Comments
	TAC/DC-37/T1-36/S2-24-4	<1E-8	6E-2	No	<1.7E-7	"Y" has succeeded, W-type sequence, Type 4 from Table Three
	TAC/DC-37/T1-36/S2-37	<1E-8	2.5E-2	No	<4.0E-7	V-type sequence, Type 3 from Table Three

the initial quantification were given in the comment sections in Table 4.10-1 of Reference 6. For those sequences not covered in this way, Table C-47 (given in the appendices of NUREG/CR-4550, Volume 4, [6]) was used in conjunction with the event tree to determine the "V_4" event probabilities that were used. Table 3.11 is a compilation of those portions of Table C-47 relevant to finding the "V_4" probability values. V-Type and W-Type sequence designators refer to loss of injection and loss of containment heat removal sequences, respectively. No recovery actions were applicable for the HPSW analysis.

Table 3.11

Human Error Probabilities for High Pressure Service Water Sequences

Type	Description of Event Tree Sequence	Total Human Error Probability (HEP)	
		V-Type Sequence	W-Type Sequence
1	Two or less safety systems failed and no operating safety systems subsequently failed.	4E-3	8E-4
2	Two or less safety systems failed and operating safety system(s) did subsequently fail.	2.5E-2	1E-2
3	More than two safety systems failed and no operating safety systems subsequently failed.	2.5E-2	1E-2
4	More than two safety systems failed and operating safety systems subsequently failed.	0.1	6E-2

The estimated frequencies with "V_4" unavailable (see Table 3.10) were totaled for each initiating event. These frequencies are listed in Table 3.12. Adding the total estimated frequencies from Table 3.12 (2.46E-5) and Table 3.9 (3.64E-6) yields a new point estimate of 2.82E-5. This is an increase of a factor of 7.8 over the NUREG-1150 value of 3.62E-6 and represents a high estimate. This point estimate would be less if time permitted a complete requantification using the SETS and TEMAC computer codes.

Table 3.12

Non-Dominant Sequence Frequencies with HPSW Unavailable Grouped by Initiating Event

Initiating Event	Estimated CDF
A	<2.3E-7
S1	<7.8E-7
S2	<8.3E-7
S3	<1.5E-7
T1	<3.22E-6
T2	<7.4E-7
T3A	<5.87E-6
T3B	<7.4E-7
T3C	<5.75E-6
TAC/DC	≤6.25E-6
Total	<2.46E-5

3.3.3 Diesel Generator Maintenance

Peach Bottom has a very reliable emergency AC power system as a result of a combination of system design and new maintenance practices. Although these factors will not prevent the initiating event of a loss of offsite power, it provides immediate accident mitigation and is considered a Phase 1 risk management practice. The system design is such that, upon loss of offsite power, any one of four diesels can supply the loads for both units. With this level of redundancy, only dependent failures of the diesels have any significant impact on the core damage frequency. Additionally, the maintenance program at Peach Bottom is such that the probability of a diesel generator failing to start has been reduced from a generic value of 3E-2 per demand to 3E-3 per demand, an order of magnitude decrease.

The station blackout frequency at Peach Bottom tends to be dominated by failures in the Emergency Service Water (ESW) system. This two train system provides cooling to the diesel generators, and failure of the system leads to diesel generator failure. This dependent failure dominates the diesel generator failure rates even when other common cause failures are considered. Analysis indicates that the reduced diesel generator failure rates do not have a large impact on the core damage frequency. Nonetheless, the diesel generator maintenance program is to be commended as a significant risk management effort that could have a large impact at other plants with less redundancy in their emergency power systems.

4. DIRECT BENEFITS FROM PRAs

In performing a PRA, important plant vulnerabilities are identified which may encourage utilities to initiate plant improvements. In general, any significant vulnerabilities are fixed by the utility when they are uncovered, often before the PRA is completed. Some of these vulnerabilities may be ones that current utility risk management programs, which are not always based on systematic evaluations, have overlooked. Also, there are usually large numbers of plant changes that a utility may be considering at any point in time, and PRA results may provide further impetus to undertake some of these changes.

The best way to illustrate the direct benefits of PRAs is by example. There are numerous risk significant changes that have occurred at the four NUREG-1150 plants during the process of completing the NUREG-1150 study. It would be incorrect to conclude that all of these changes occurred solely as a result of NUREG-1150; indeed, many of the changes are a result of industry initiatives and utility decisions. Nonetheless, we do believe that NUREG-1150 and other PRA studies have contributed to the process and increased the priority of many of these changes. In the sections below, we identify some of the most important plant changes that occurred during the NUREG-1150 process and evaluate their perceived impact on the final NUREG-1150 results.

4.1 Direct Benefits at Surry

Numerous changes have occurred at Surry during the past three years. Examples of some of the more significant Phase 1 and 2 changes from a probabilistic risk viewpoint are:

1. Uninterruptible power supplies have been provided for vital instrumentation buses.

2. New heat exchanger valves have been added to the Containment Spray Recirculation system.

3. Operating emphasis has changed so that block valves on the atmospheric dump valves are more likely to be open.

Each of these changes and its potential significance is discussed in the following sections. Quantitative evaluations are included where possible.

4.1.1 Uninterruptible Power Supplies

A significant Phase 1 hardware configuration change has been made at Surry concerning the power supplies to the four 120 VAC vital Instrumentation and Control (I and C) buses. Previously, two vital buses were powered by DC buses via inverters and the other two were powered by

480 VAC buses via solatron transformers. In the event of a loss of a 480 VAC bus, the associated 120 V vital I and C bus was also lost, resulting in a turbine trip because the vital buses on the solatron transformers power the turbine control system. The reactor trips following the turbine trip. Previously, the plant had often been operated with the atmospheric dump valves (ADVs) inoperable. The abrupt turbine runback, combined with inoperable ADVs, caused the pressure and temperature in the steam generators to increase above normal post-trip levels. This results in an increased cold leg temperature and subsequent high primary system temperature. Thus, the power-operated relief valve (PORV) demand probability in this situation was assessed to be 1.0. A transient-induced loss of coolant accident (LOCA) will result if the PORV sticks open. The LOCA can not be isolated in this instance since the block valve is powered by the failed 480 V bus.

The four vital 120 VAC buses are now each powered by uninterruptible power supplies (UPS), which are fed by three sources. The loss of a 480 VAC bus is no longer considered an initiating event. A reactor trip does not result, since the 120 VAC buses do not lose power and the turbine control system is unaffected. If a stuck-open PORV results from other initiating events, power to the block valve is maintained and the PORV can be isolated.

In order to quantify the core damage frequency (CDF) change due to the addition of uninterruptible power supplies, numbers from the original NUREG/CR-4550 Surry report [7] were examined. Current Surry analyses do not include T_4 (loss of 480 V bus) events as initiators. Four T_4 sequences were dominant in the original 4550 analysis. The affected sequences and their point estimate probabilities are given in Table 4.1. If the plant changes had not been made, and the T_4 sequences were to be included in the current analysis, the point estimate of the core damage frequency at Surry would be increased by 5.00E-6 to 3.84E-5, based on the frequency of these sequences in the original analysis.

4.1.2 Containment Spray Recirculation System Heat Exchanger Valves

Containment heat removal at Surry is provided by the Inside and Outside Containment Spray Recirculation systems, each of which is a two train system. Thus, there are a total of four heat exchangers available to remove containment heat loads. Cooling for the heat exchangers is provided by a gravity flow service water system. Two pipe trains supply service water to a header connected to all four heat exchangers. Each pipe train contains two inlet valves in parallel, with only one of four valves needed to be open to supply sufficient cooling water to the heat exchangers.

In 1983 an incident occurred in which all four valves failed to open upon demand. This failure was due to a combination of marine growth and corrosion. As a result of this failure, the valve test interval was

Table 4.1

Sequences Eliminated Due to Addition of UPS

Sequence	Description	Annual Sequence Frequency
$T_{4J}QH_1$	Failure of 480V Bus 1J and low pressure recirculation	1.9E-6
$T_{4H}QH_1$	Failure of 480 V bus 1H and low pressure recirculation	1.6E-6
$T_{4J}QH_2$	Failure of 480 V bus 1J and high pressure recirculation	8.1E-7
$T_{4H}QH_2$	Failure of 480 V bus 1H and high pressure recirculation	6.8E-7
Total Reduction in CDF		5.0E-6

changed from 18 months to 3 months. The original NUREG/CR-4550 analysis [7] used a plant-specific data analysis that factored in the changed test interval and produced a median value of 0.011 per demand for the common cause failure of all four service water valves.

More recently, in 1986, the actual valves were replaced by valves containing material more resistant to marine growth that require less torque to open. No additional common cause failures have been observed since the 1983 incident. As a result of the new valves and additional operating data, the revised NUREG/CR-4550 analysis [4] used a mean value of 6.3E-4 per demand for the common cause failure of the four valves.

The impact of this Phase 2 change can be seen by examining the plant damage states that involve the total loss of containment heat removal. The frequencies of the plant damage states as calculated for the original analysis are summarized in Table 4.2. In the new analysis, no accident sequences with a frequency above 1E-7 were identified; thus, no plant damage state frequencies were developed. Overall, we estimate that each of the sequences (and therefore the plant damage states) dropped about an order of magnitude. While this may not be a particularly large change to the total core damage frequency, the risk impact could be important since these are accident sequences in which containment heat removal is lost and containment failure may precede core damage.

Table 4.2

Plant Damage States Involving Loss of Containment Heat Removal (CHR) (Previous Analysis)

PDS	Description	Mean Frequency
SYNI	Small LOCAs with failure of recirculation and CHR	5.0E-8
AYNB	Large and Medium LOCAs with failure of CHR and subsequent ECCS failure	8.3E-8
AYNI	Large and Medium LOCAs with failure of recirculation and CHR	6.2E-8
TYNI	Transient with failure of auxiliary feedwater, CHR, and subsequent ECCS failure	9.5E-10
Total for These Plant Damage States		2.0E-7
Current Analysis Estimate		3.0E-8

4.1.3 Status of Block Valves

At Surry, as with most PWRs, block valves are provided for the pressurizer relief valves (PORVs) and the atmospheric dump valves (ADVs). The block valves are used to isolate a PORV or ADV that should happen to stick in the open position. Often, a plant will operate with one or more of these block valves closed to stop leakage from PORVs or ADVs.

The PORVs and ADVs can be important during many accident sequences. As discussed later in Chapter 3, feed and bleed cooling and secondary blowdown can be important factors in accident response. Feed and bleed cooling requires opening two PORVs at Surry, while secondary blowdown requires opening all of the ADVs. In some accident sequences, power to the block valves is lost, so that if the block valves are closed at the start of the accident, feed and bleed cooling may not be available.

In the original Surry analysis [7] it was determined, based on operating experience at Surry, that at least one PORV block valve would be closed 50% of the time and both block valves would be closed 10% of the time. The ADV block valves, on the other hand, were closed most of the time. Plant operations did not emphasize the availability of the PORVs and ADVs.

NUREG-1150 analysts determined that PORV and ADV availability was poor. The revised analysis, discussed in Reference 4, reflects that Surry operations personnel are more aware of the importance of having the PORVs and ADVs available. The new analysis assumes that each PORV is unavailable 30% of the time and that each ADV is unavailable 15% of the time. The importance of the PORVs and ADVs to feed and bleed cooling and secondary blowdown was discussed in Section 3, and these Phase 2 changes to the block valve status are important factors in the evaluation of those risk management actions.

4.2 Direct Benefits at Peach Bottom

As with Surry, numerous changes have occurred at Peach Bottom during the past three years. Examples of some of the more significant changes are:

1. Changes have been made to the Emergency Service Water system to increase the reliability of a key flow path.

2. Revised procedures have been implemented for containment venting and station blackout.

3. A revised analysis of containment pressure capacity has been performed.

Each of these Phase 2 and 4 changes and its potential significance is discussed in the following sections. Quantitative evaluations are included where possible.

4.2.1 Emergency Service Water System

The Emergency Service Water (ESW) system has a common discharge valve on the flow path to the river, labeled MV0498 on the Peach Bottom ESW schematic (see Figure 4.1). Operating procedures have been changed to ensure that ESW system blockage does not occur due to inadvertent closure of MV0498 and to clarify under what conditions the valve may be closed for maintenance.

In the original NUREG/CR-4550 analysis [8], closure of MV0498 causes flow to be diverted through the Emergency Diesel Generator (EDG) coolers, ESW Booster pumps, Fans and possibly, the Emergency Cooling Water (ECW) pump. The plant-specific value for MV0498 unavailability due to maintenance used in the original analysis was based on operational experience for MV0498. It was assumed that sufficient head does not exist to pump water to the loads and the cooling tower structure with MV0498 shut and both booster pumps inoperative. High pressure pump trips are associated with the ESW system due to the likelihood of pump damage when operating at the shutoff head. This implies that closure of MV0498 affects the ESW loads, and the failure of diesel generator cooling could lead to station blackout following loss of offsite power.

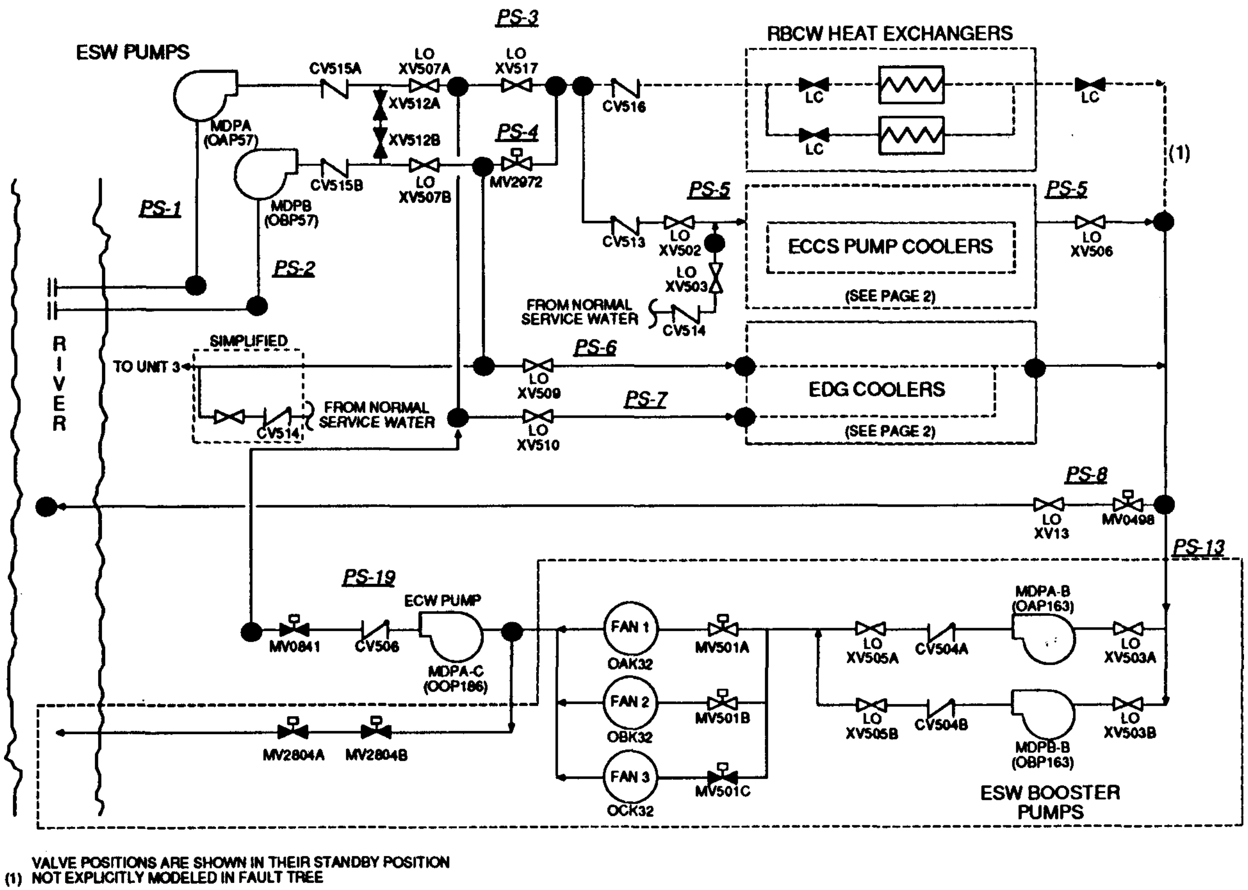
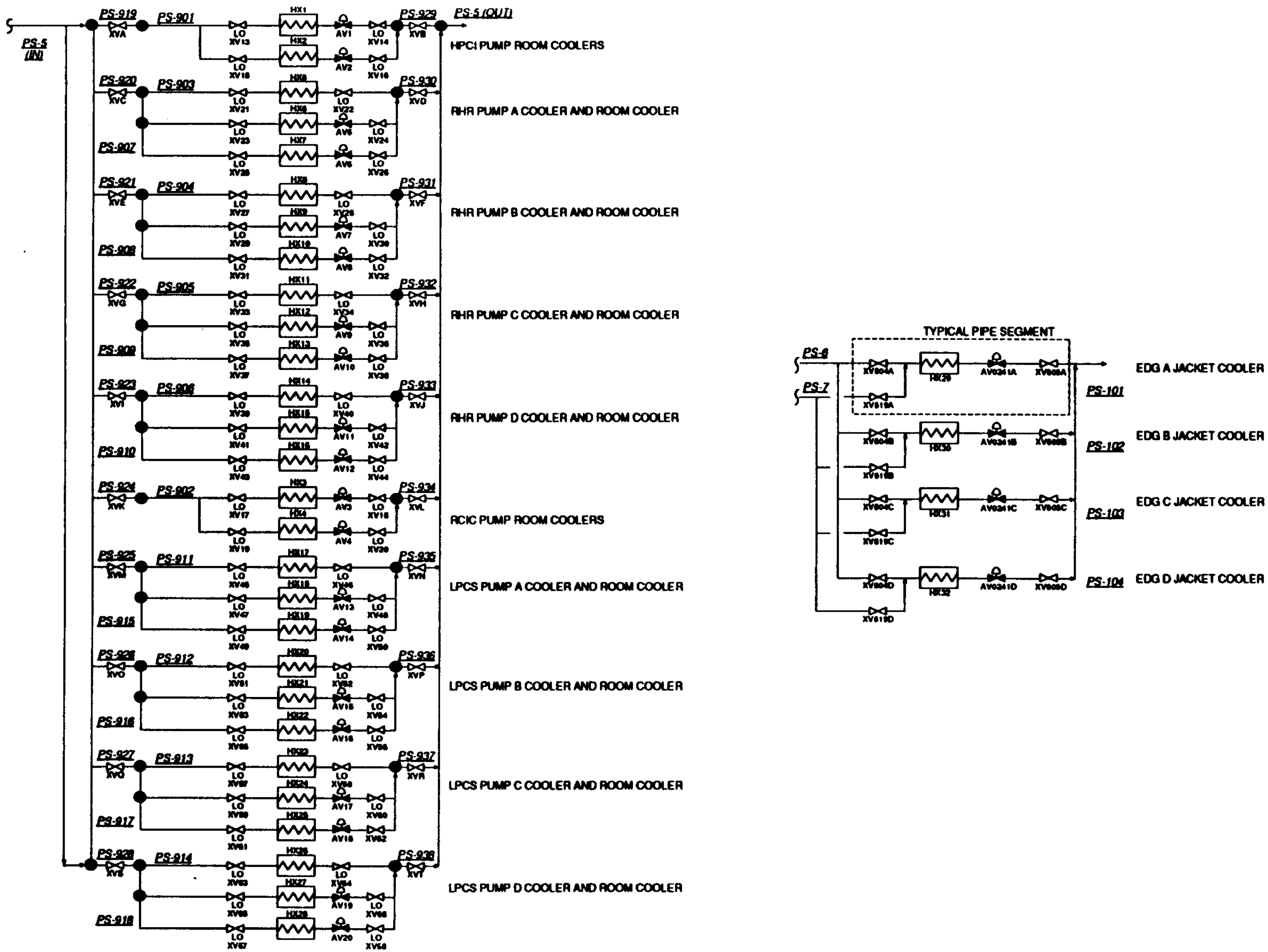


Figure 4.1. Emergency Service Water System Schematic.
(Page 1 of 2)



VALVE POSITIONS ARE SHOWN IN THEIR STANDBY MODE

Figure 4.1. Emergency Service Water System Schematic.
(Page 2 of 2)

In the revised analysis [6], Peach Bottom procedures for MV0498 closure were changed. The valve actuation circuitry no longer permits the valve motor to receive an inadvertent closure signal. Further, strict procedures were developed for when and under what conditions the valve may be closed for maintenance. These actions reduce the failure probability of the ESW system. However, during a maintenance outage of MV0498, there must be enough flow through an alternate flow path that all loads are properly cooled and there is no problem with pressure buildup in the system.

Peach Bottom is in the process of adding manual valves to the piping into and out of each room cooler (see page 2 of the ESW schematic, XVA through XVT). This allows any room cooler to be isolated for maintenance tasks while the rest of the system is still operating. Credit was taken for this hardware change in the final analysis. Further, the plant has provided evidence that the booster pumps are not required to provide circulation through the cooling towers. Therefore, even with the ESW booster pumps unavailable, pressure buildup in the system is not a problem.

The Phase 2 physical and procedural improvements to the Emergency Service Water system had a negligible effect on accident sequence quantification, given that the booster pumps are not necessary for successful operation of the ESW system. The changes provide an added assurance of the reliability of the system, but they do not decrease the core damage frequency significantly. The assessment that the booster pumps are not necessary significantly decreased the perceived risk and illustrates the need to accurately assess system requirements and dependencies in the plant modeling process.

4.2.2 Containment Venting and Station Blackout Procedures

Phase 2 changes were recently made at Peach Bottom concerning the procedures for containment venting and station blackout scenarios.

Containment venting procedures in the original NUREG/CR-4550 analysis [8] required venting to occur when the containment pressure reached 60 psig. The revised NUREG/CR-4550 analysis requires venting to occur at 100 psig. Peach Bottom is in the process of changing this value back to 60 psig. The venting pressure affects the Safety Relief Valve (SRV) operation in the drywell. The SRVs remain open due to differential pressure between a nitrogen supply and containment, which is normally 95-115 psid. If venting is required at 100 psig, this differential pressure will be near zero and the SRVs may drift closed. This results in primary system pressure increase and eventual failure of the low pressure cooling systems [i.e., Low Pressure Core Spray (LPCS) and Low Pressure Coolant Injection (LPCI)]. If the Control Rod Drive (CRD) system is operating, venting at either 100 psig or at 60 psig does not result in core damage sequences (Peach Bottom ADS valves have only been pressure tested to 60 psig, so their behavior at 100 psig is unknown). If the CRD system is lost, only low pressure cooling is available and some sequences utilizing the 100 psig venting criteria go to core damage. For this case, if the core is boiled off before the containment reaches 100 psig and the operator vents, core damage occurs. Low pressure cooling can be restored if the operator vents before the core is boiled off. The thermal-hydraulic analyses indicate that boil-off occurs before the time at which the operator vents. If procedures require venting at 60 psig, the containment pressure will not be allowed to rise to 100 psig and disable core cooling, which will eliminate a number of current core damage sequences.

The original containment venting procedures allowed local action (i.e., operators could manually open air-operated valves utilized for venting by opening the regulators on air tanks). This was performed if control room operation of the valves did not work. The new procedures do not allow local action, due to high radiation and possible steam in the reactor building. The ductwork may rupture due to high pressure, allowing steam to escape into the reactor building. The sequence frequencies which gave credit for local action are now increased since that credit has been removed, but it is not a significant increase. Only a slight impact on the accident sequences occurred in the revised analysis from increasing the containment venting pressure from 60 psig to 100 psig and revising local action procedures. The TW sequences (transient followed by loss of containment overpressure protection systems) are now more important than the original analysis indicated but the change was one of an already low core damage frequency increasing slightly.

The station blackout procedures at Peach Bottom have recently incorporated two changes. The first change specified DC loads to be shed during station blackout conditions. The resulting load reduction enables the batteries to operate for approximately 12 to 15 hours. Without shedding unnecessary DC loads, the batteries nominally last 6 hours. The total core damage frequency has been reduced due to these load shedding capabilities. A detailed analysis would be required to determine the factor of decrease. The second change was the addition of written, detailed steps for the operation of the HPCI/RCIC systems when the batteries are depleted. This change eliminates a potential failure mode, although the effect on the accident sequences is minimal.

4.2.3 Containment Pressure Capacity

During the course of a PRA, changes occur in the model used to represent a plant. These changes lead to a more accurate portrayal of the plant. An example of such a change concerns the containment failure pressure at Peach Bottom, which affects Phases 2 and 4.

In the original Peach Bottom NUREG-1150 report [8], analysts suggested that the containment (i.e., the drywell and/or the wetwell) would fail at approximately 130 psia. The revised analysis showed that failure would occur at approximately 170 psia (mean value). For this re-analysis, a probability distribution was used to reflect the uncertainty in the exact failure pressure. A more detailed analysis of the failure location and mode was also performed.

All aspects of the containment failure process (i.e., the failure pressure, location, and mode) are important to different portions of the analysis for different reasons. The failure pressure is important in the front-end analysis since the time at which the failure pressure is reached determines the extent of core damage for some scenarios. The amount of time elapsed for boiloff and core uncovery will determine if any core damage occurs for the TW and ATWS sequences. Given low pressure injection has been established, high containment pressure may compromise the ability to inject to the core. As the differential pressure between the ADS valve nitrogen supply (for opening the ADS valves) and containment approaches zero, which occurs at a containment pressure of approximately 95 to 115 psig, the ADS valves drift closed and the reactor vessel repressurizes. Low pressure injection soon fails and boiloff begins to lower the water level in the reactor vessel. If the containment fails before the water level is low enough for core damage to begin, decreasing containment pressure establishes a differential pressure between containment and the ADS nitrogen supply. The ADS valves will then open, the primary system pressure will decrease, and low pressure cooling can then be established to prevent core damage, although some low pressure injection systems that draw from the suppression pool may not be available at this point due to saturated pool conditions. If containment failure occurs after core damage has begun but before vessel breach, reflooding the damaged core may arrest core damage and prevent vessel breach. In the back-end analysis, a higher failure pressure will allow more time for recovery of various systems and for deposition of fission products in the containment.

Indirectly, the failure pressure affects the likely mode and location of the containment failure. As containment pressure increases, the probable failure location changes. The three locations for containment failure are 1) the drywell head to the refueling floor, 2) the drywell to the reactor building, and 3) the torus (wetwell) to the reactor building, above or below the water line. As the failure pressure increases, the failure mode changes from a leak to a rupture. A leak is defined as an opening (10 square inches to 1.8 square feet) that would result in a slow (> 2 hour) containment depressurization. A rupture is defined as an opening (> 1.8 square feet) that would result in rapid (< 2 hour) containment depressurization.

If the location of the failure is such that the flow is to the reactor building, a severe environment can be created which leads to an increased probability of failure for all systems that have equipment in the building. This problem was examined using thermal-hydraulic analyses to calculate environments and an expert judgement elicitation to quantify equipment failure probabilities in these environments. Also, failure within the reactor building or to the refueling floor will change the decontamination factor for fission product release. Failure in the suppression pool above or below the water line will affect the amount of suppression pool bypass that occurs. The relative probability of each failure location changes as the pressure increases, therefore the failure pressure used for the base case directly affects the sequence quantification.

The mode of failure affects system operability. If the mode is a leak, containment pressure will remain high, the ADS valves will remain closed and low pressure injection will be unavailable. If the failure mode is a rupture, the containment will depressurize and low pressure injection systems may be utilized, if the environment does not fail the systems. The LPCI system can not pump saturated water; therefore LPCI will fail if the pool is saturated as a result of the containment failure whether the failure mode is a leak or a rupture. This directly affects the accident sequence quantification. In the back-end analysis, the failure mode also affects the rate at which fission products are released and the duration of the release.

The re-analysis did not significantly affect the TW sequences since these sequences were already evaluated to have low frequencies of occurrence. However, the resolution of the ATWS sequences is changed. The back-end results will be influenced by the more accurate representation of both the best estimate and the uncertainties in the various modes and locations of the containment failure. These will give a better representation of the possible source terms that can result from different accident progressions.

4.3 Direct Benefits at Sequoyah

While numerous changes have occurred at Sequoyah during the past three years, few of them have had an impact on the PRA results. A new assessment of charging pump cooling requirements provided to the NUREG-1150 analysts is one example of a significant phase 2 change. This change and its potential significance is discussed in the following section. A quantitative evaluation of its importance is included.

4.3.1 Charging Pump Cooling

As noted previously, significant insights into the workings of a plant can occur during the course of a PRA. These insights may cause major changes in our perception of plant risk, even if they do not lead directly to any plant changes. An example of such an insight concerns cooling requirements for charging pumps at Sequoyah.

The original charging pump cooling analysis for NUREG-1150 presented in Reference 9 was based on an assessment that, during an accident, the charging and safety injection pumps required both seal cooling by the Component Cooling Water (CCW) system and lubricating oil cooling by the Service Water System. In turn, the charging pumps provide seal injection flow to the reactor coolant pumps (RCPs). The CCW system also provides cooling water to the reactor coolant pump (RCP) thermal barrier heat exchanger. Thus, if CCW fails, both the seal injection and thermal barrier methods of RCP seal cooling are lost. This condition leads to RCP seal failure in a short period of time and, subsequently, a small LOCA. Because of the previous CCW failure, the charging and safety injection pumps would be inoperable, leaving no way for the plant to maintain the water inventory in the primary system. Containment sprays would also fail, since they depend on CCW for lubricating oil cooling, resulting in a sequence with a potentially high risk significance. The sequence of interest, T_{CCW}, had a point estimate frequency of 2.7E-5 out of a total CDF of 8.6E-5.

As a result of reviewing the material in Reference 9, plant personnel have investigated this issue further and supplied compelling evidence [10] that the centrifugal charging pumps in question do not require seal cooling to operate in the sequences of interest. In the seal injection mode, the pumps will be pumping water from the Volume Control Tank. With the expected low water temperature, the charging pumps will be able to operate for many hours before a problem occurs due to lack of cooling. Thus, RCP seal cooling continues despite a loss of CCW, thereby eliminating the risk of a seal LOCA.

Given the new information, the T_{CCW} sequence has been rendered probabilistically unimportant. The revised analysis has rendered moot most concerns about the reliability of the CCW system, and may have prevented unwarranted efforts to improve it.

4.4 Direct Benefits at Grand Gulf

Numerous changes have occurred at Grand Gulf during the past three years. Examples of the more significant changes are:

1. Modifications have been made to the Firewater System to allow its use in additional sequences.

2. New Emergency Operating Procedures have been implemented.

3. A new assessment of High Pressure Core Spray Pump failure at high temperatures has been provided to the PRA team.

Each of these Phase 2 changes and its potential significance is discussed in the following sections. Quantitative evaluations are included where possible.

4.4.1 Firewater System

Initial NUREG-1150 PRA analysis efforts for Grand Gulf considered utilization of the Firewater system for emergency coolant injection, but did not give any credit for this action based on inadequate procedures and hardware configurations. In order to obtain credit for the system in the revised analysis, the plant has made significant system and procedural modifications. As a result, the Firewater system at Grand Gulf can now be used as a backup source of low pressure coolant injection to the reactor vessel. The system is used for long-term accident sequences in which makeup water is provided by other injection systems for several hours before their subsequent failure. The Firewater system primarily aids the plant during station blackout conditions and is considered a last resort effort.

A simplified schematic of the Firewater system is provided by Figure 4.2. The system has two diesel-driven pumps and one motor-driven pump, which draw from either of two water storage tanks. The motor-driven pump requires AC power. The two diesel-driven pumps have no outside interfaces or dependencies. Each pump has self-contained batteries which provide it with power. Since the major benefit of the Firewater system is during station blackout conditions, the diesel-driven pumps are important. However, the reactor vessel must be depressurized with ADS to utilize the Firewater system. Since the ADS valves require DC power, Firewater can only be used in station blackout conditions until the batteries deplete.

The modifications to the Firewater system concern fire hose adapters used to connect fire hoses to various injection systems within the plant. These adapters were not readily available for use in emergency situations. Adapters were manufactured and located in the plant so they may be utilized in a timely manner when needed. The Firewater system was also put into the plant emergency operating procedures as a source of coolant injection. The final change was to ensure that all Firewater connections are clearly marked within the plant.

The Firewater system is manually initiated. To align the system, the operator connects the fire hose to the chosen injection line and opens the valve(s) in that line. The diesel-driven pumps start automatically once the firewater valve is opened.

To determine the significance of the Firewater system to the Grand Gulf core damage frequency, both the dominant sequences and those sequences previously screened out were re-examined. Initially, station blackout plant damage states quantified as part of the NUREG/CR-4550 analysis were identified and requantified with the Firewater system unavailability set to unity. This removes the effect of the Firewater system from the core damage frequency. This process involved the following steps:

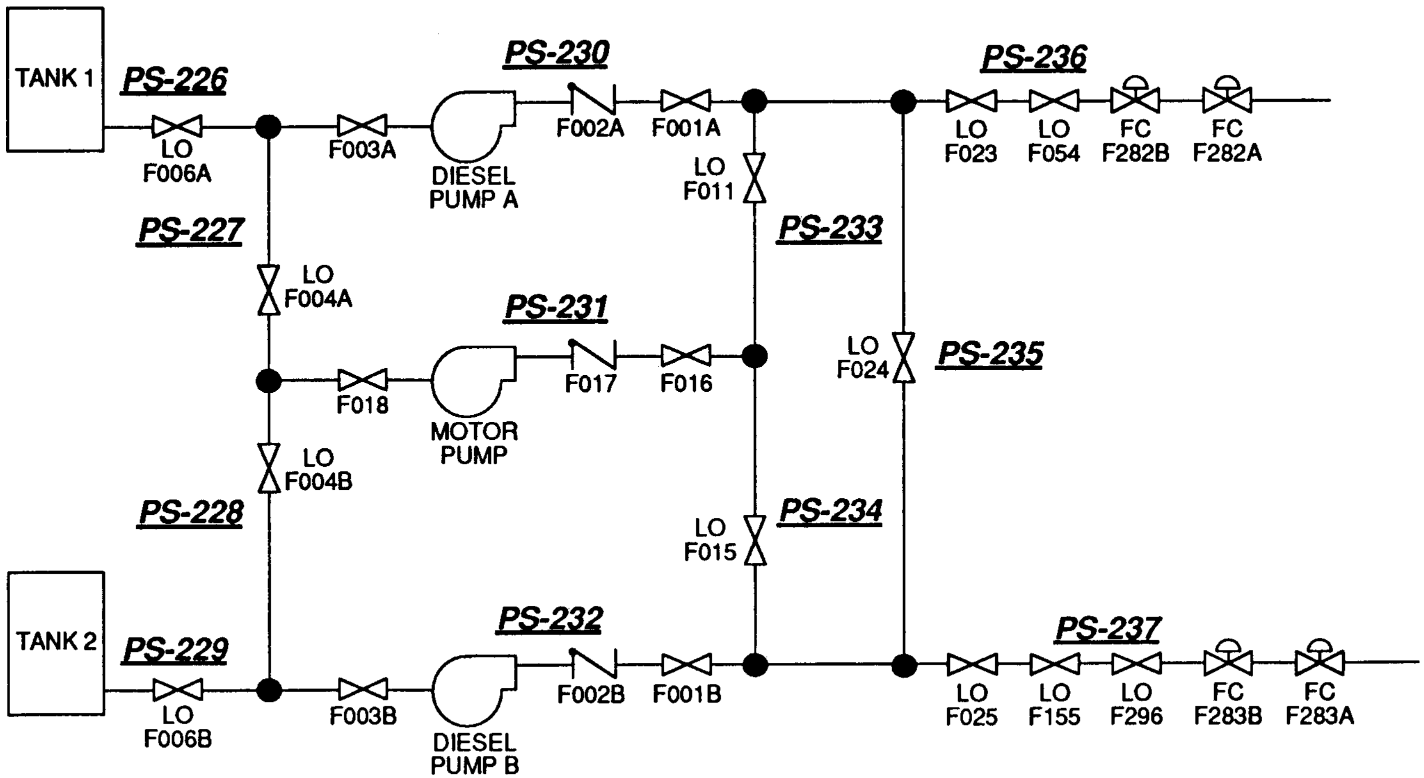


Figure 2.2. Firewater System Schematic.

(1) The dominant accident sequences (i.e., any sequence with core damage frequency above 1E-8) involving the Firewater system were identified. All sequences involved station blackout scenarios.

(2) The cut sets of the identified sequences were examined to identify those events which involved failures of the Firewater system. A single event, FWS-XHE-ALIGN, dominated the Firewater system failure. This event represents a failure of the operator to properly align and actuate the Firewater system for injection. In the initial quantification steps for the revised analysis, the basic event FWS-XHE-ALIGN was set to 1.0 for screening purposes, which ensures the operator will fail to align the Firewater system. If this event appeared in a dominant cut set in the final quantification steps, a more realistic value was calculated using HRA methodology. The dummy basic event, RA-FWSACT-12HR, was created and included in the cutsets with every appearance of the basic event FWS-XHE-ALIGN. The latter event retained the value of 1.0. A probability of 2.0E-2 was calculated for the dummy event. The combination of these two events in the cutsets results in the correct probability at Grand Gulf that the operator will fail to properly configure the Firewater system for injection. These two events comprise approximately 99% of the unavailability of the Firewater system.

(3) The plant damage states resulting from the above dominant sequences were identified. These plant damage states (PDS4, PDS5, and PDS6) and the entire plant model were requantified with the probability of the basic event RA-FWSACT-12HR set to 1.0. This effectively eliminates the Firewater system (event "V_5" in the event tree) from the analysis.

A comparison between the plant damage state frequencies calculated for the NUREG/CR-4550 analysis and those calculated without the Firewater system is given in Table 4.3. Increases of a factor of 33 for the frequencies of the plant damage states PDS4, PDS5 and PDS6 are realized when the Firewater system is eliminated. However, the total core damage frequency increased only by a factor of 1.3. The Firewater system has a significant impact on some of the lesser station blackout plant damage states, but does not greatly influence the dominant station blackout plant damage states which contain short term sequences at high pressure, for which the Firewater system could not be utilized.

To determine the significance that the Firewater system has on the non-dominant sequences, all of the accident sequences involving the Firewater system were reviewed. Sixty-three previously non-dominant sequences involved the Firewater system (event "V_5").

Table 4.3

Dominant Sequence Frequencies with Firewater System Unavailable

Plant Damage State	Current Frequency	Frequency Without Firewater	Factor of Increase
PDS4	2.0E-8	6.8E-7	33
PDS5	5.9E-10	2.0E-8	33
PDS6	1.9E-9	6.3E-8	33
Total Plant	2.1E-6	2.8E-6	1.3

These sixty-three sequences were requantified with the probability for Firewater system unavailability set to 1.0. Table 4.4 is a compilation of these sequences, which are described in the revised Grand Gulf NUREG/CR-4550 report [11]. Shown are the accident sequence numbers, descriptors and frequencies from Tables 4.10-1 and 4.10-3 in Reference 11. In the tables from Ref. 11, sequence frequencies are shown before and after appropriate recovery actions were applied to the cutsets by the NUREG-1150 analyst. Table 4.4 also lists the new frequency of the accident sequence without the Firewater system, relevant comments, and whether the sequence could be eliminated. All sequences which had a frequency less than 1.0E-8 were eliminated.

The approach used to determine the new frequencies involved identifying the probabilities used for Firewater system unavailability in the Ref. 11 analysis, which varied depending on the sequence. The estimated frequencies of the sequences from Ref. 11 'after recovery', or, if no recovery was applied, 'before recovery', were then divided by the value for the unavailability of the Firewater system. This resulted in the new sequence frequencies without credit for the Firewater system.

All of the Firewater system values used in the final quantification (i.e., NUREG/CR-4550 analysis after recovery) are indicated in the comment section of Table 4.4. The frequencies of the sequences which were not eliminated (all had frequencies >1.0E-8) were grouped together by initiating event. Table 4.5 is a list of these non-dominant sequence frequencies grouped by initiating event.

Adding the non-dominant sequence frequencies from Table 4.5 (1.61E-6) to the dominant system frequency (2.8E-6) yields a new point estimate of the core damage frequency of 4.4E-6. This is an increase of a factor of 2.1 over the revised NUREG/CR-4550 analysis value of 2.1E-6 and is a conservative estimate due to assumptions made when recovering the previously non-dominant sequences.

Many sequences in Table 4.4 were given the cutoff value frequency of 1.0E-8. Although the actual frequency is lower, this conservatively estimates their contribution to the core damage frequency without considering the benefit of the Firewater system.

4.4.2 Emergency Operating Procedures

Grand Gulf Operating Procedures (OPs) have been revised since the original NUREG/CR-4550 analysis [12] was performed. Many OP updates reflect changes to the GE Emergency Procedures Guidelines (EPG). Earlier Grand Gulf OPs were based on Rev. 1B of the GE EPG [13] and updated OPs are now based on Rev. 3 of the GE EPG [14]. Plant-specific operating procedure changes were also made which are reflected in the revised Grand Gulf report.

GE operating procedures used by Grand Gulf personnel during the time of the original analysis were written in a prose format. Updated GE procedures are written in a flowchart format, which is easier for operators to understand and follow. Therefore, more credit is given to operators for following procedures during accident conditions, which is reflected in lower operator error probabilities for diagnosis and action.

Most procedural changes resulting from Rev. 3 of the GE EPG [14] concern operator response to ATWS scenarios. The earlier procedures do not allow operators to initiate Standby Liquid Cooling (SLC) until reactor power exceeds a certain percent. Updated procedures include this restriction for most cases but make an allowance for the operators to initiate SLC before the pool temperature reaches 110°F. This gives the operator greater flexibility to observe trends in reactor conditions and react accordingly. For instance, the operator may notice a rapidly escalating suppression pool temperature and initiate SLC at 95°F, and yet not be as concerned by a higher suppression pool temperature which is increasing very slowly. Another new EPG procedure dealing with ATWS conditions is to inhibit the Automatic Depressurization system (ADS) following initiation of SLC. Generally, the above EPG changes give the operator more capability to control power in an ATWS situation by controlling the reactor water level and pressure.

Updated, plant-specific OPs were also utilized in the revised Grand Gulf analysis. Two OPs have recently been incorporated at the plant

(text continued on page 23)

Table 4.4

Non-Dominant Sequences Quantified with Firewater System Unavailable

Accident Sequence	Event Tree Sequence	NUREG-1150 Sequence Frequency Before Recovery (per year)	NUREG-1150 Sequence Frequency After Recovery (per year)	Frequency With "V_5" Unavailable	Sequence Eliminated	Comments
11	S2-12	1.3E-8	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
13	S2-19	3.0E-8	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
17	S3-a/T3A-19	3.3E-10	--	6.6E-10	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
18	S3-a/T3A-24	3.7E-10	--	7.4E-10	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
19	S3-a/T3A-31	8.0E-10	--	1.6E-9	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
20	S3-a/T3A-36	9.3E-10	--	1.9E-9	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
21	S3-a/T3A-39	1.0E-10	--	2.0E-10	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
22	S3-a/T3A-41	2.5E-10	--	5.0E-10	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
25	S3-a/T3A-83	9.3E-9	--	1.9E-8	No	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
26	S3-b/S2-12	1.3E-9	--	2.6E-9	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
28	S3-b/S2-19	3.0E-9	--	6.0E-9	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
32	T1-17	<1.0E-9	--	<2.0E-9	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.

Table 4.4 (Cont.)

Non-Dominant Sequences Quantified with Firewater System Unavailable

Accident Sequence	Event Tree Sequence	NUREG-1150 Sequence Frequency Before Recovery (per year)	NUREG-1150 Sequence Frequency After Recovery (per year)	Frequency With "V_5" Unavailable	Sequence Eliminated	Comments
33	T1-23	3.3E-6	9.9E-10	5.0E-8	No	Sequence estimated frequency for "V_5" was 2E-2.
38	T1-78	<1.0E-9	--	<2.0E-9	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
40	T1-84	1.3E-7	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
43	T1-107	2.8E-3	5.5E-9	2.8E-7	No	Sequence estimated frequency for "V_5" was 2E-2.
51	T1B-3	1.5E-5	4.6E-9	2.3E-7	No	Sequence estimated frequency for "V_5" was 2E-2.
55	T1B-10	6.0E-7	1.8E-10	9.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
58	T1B-14	5.2E-5	1.5E-8	7.5E-7	No	Sequence estimated frequency for "V_5" was 2E-2.
62	T1B-19	2.1E-6	6.0E-10	3.0E-8	No	Sequence estimated frequency for "V_5" was 2E-2.
65	T2-18	3.6E-6	4.0E-10	2.0E-8	No	Sequence estimated frequency for "V_5" was 2E-2.
66	T2-25	8.8E-6	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
73	T2-b/S2-12	2.8E-7	2.6E-10	1.3E-8	No	Sequence estimated frequency for "V_5" was 2E-2.
75	T2-b/S2-19	6.5E-7	6.5E-10	3.3E-8	No	Sequence estimated frequency for "V_5" was 2E-2.
79	T2-c/T1-17	<1.6E-12	--	<3.2E-12	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
80	T2-c/T1-23	5.3E-9	--	1.1E-8	No	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
85	T2-c/T1-78	<1.6E-12	--	<3.2E-12	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.

Table 4.4 (Cont.)

Non-Dominant Sequences Quantified with
Firewater System Unavailable

Accident Sequence	Event Tree Sequence	NUREG-1150 Sequence Frequency Before Recovery (per year)	NUREG-1150 Sequence Frequency After Recovery (per year)	Frequency With "V_5" Unavailable		Comments
87	T2-c/T1-84	2.1E-10	--	4.2E-10	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
90	T2-c/T1-107	4.5E-6	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
98	T2-c/T1b-3	2.4E-8	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
102	T2-c/T1b-10	9.7E-10	--	1.9E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
105	T2-c/T1b-14	8.4E-8	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
109	T2-c/T1b-19	3.4E-9	--	6.8E-9	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
112	T3A-19	5.0E-8	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
113	T3A-24	5.6E-8	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
114	T3A-31	1.2E-7	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
115	T3A-36	1.4E-7	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
123	T3A-b/S2-12	7.8E-7	7.2E-10	3.6E-8	No	Sequence estimated frequency for "V_5" was 2E-2.
125	T3A-b/S2-19	1.8E-6	1.8E-9	9.0E-8	No	Sequence estimated frequency for "V_5" was 2E-2.
129	T3A-c/T1-17	<4.5E-12	--	<9.0E-12	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
130	T3A-c/T1-23	1.5E-8	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
135	T3A-c/T1-78	<4.5E-12	--	<9.0E-12	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.

Table 4.4 (Cont.)

Non-Dominant Sequences Quantified with Firewater System Unavailable

Accident Sequence	Event Tree Sequence	NUREG-1150 Sequence Frequency Before Recovery (per year)	NUREG-1150 Sequence Frequency After Recovery (per year)	Frequency With "V_5" Unavailable	Sequence Eliminated	Comments
137	T3A-c/T1-84	5.9E-10	--	1.2E-9	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
140	T3A-c/T1-107	1.3E-5	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
148	T3A-c/T1B-3	6.8E-8	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
152	T3A-c/T1B-10	2.7E-9	--	5.4E-9	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
155	T3A-c/T1B-14	2.4E-7	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
159	T3A-c/T1B-19	9.5E-9	--	1.9E-8	No	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
165	T3B-a/T2-18	1.7E-8	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
166	T3B-a/T2-25	4.1E-8	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
173	T3B-c/S2-12	1.3E-7	1.2E-10	6.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
175	T3B-c/S2-19	3.0E-7	3.0E-10	1.5E-8	No	Sequence estimated frequency for "V_5" was 2E-2.
179	T3B-d/T1-17	<7.6E-13	--	<1.5E-12	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
180	T3B-d/T1-23	2.5E-9	--	5E-9	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
185	T3B-d/T1-78	<7.6E-13	--	<1.5E-12	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
187	T3B-d/T1-84	9.9E-11	--	2.0E-10	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.

Table 4.4 (Cont.)

Non-Dominant Sequences Quantified with
Firewater System Unavailable

Accident Sequence	Event Tree Sequence	NUREG-1150 Sequence Frequency Before Recovery (per year)	NUREG-1150 Sequence Frequency After Recovery (per year)	Frequency With "V_5" Unavailable	Sequence Eliminated	Comments
190	T3B-d/T1-107	2.1E-6	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
198	T3B-d/T1B-3	1.1E-8	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
202	T3B-d/T1B-10	4.6E-10	--	9.1E-10	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
205	T3B-d/T1B-14	4.0E-8	<1.0E-10	<5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.
209	T3B-d/T1B-19	1.6E-9	--	3.2E-9	Yes	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
212	T3C-a/S2-12	6.1E-9	--	1.2E-8	No	Sequence estimated frequency for "V_5" was at a screening value of .5. No recovery was applied.
214	T3C-a/S2-19	1.4E-8	<1.0E-10	5.0E-9	Yes	Sequence estimated frequency for "V_5" was 2E-2.

Table 4.5

Non-Dominant Sequence Frequencies With Firewater System Unavailable

Initiating Event	Description	Frequency
S3	Very Small LOCA	1.9E-8
T1	Loss of Offsite Power	3.30E-7
T1B	Station Blackout	1.01E-6
T2	Transient with Loss of PCS	7.7E-8
T3A	Transient with PCS Available	1.45E-7
T3B	Loss of Feedwater	1.5E-8
T3C	IORV Transient	1.2E-8
Total		1.61E-6

the High Pressure Core Spray (HPCS) diesel generator and the Firewater system. The HPCS system is provided with a dedicated diesel generator as a source of onsite power independent of the primary diesel generators, ensuring the availability of high pressure injection in station blackout conditions. During a station blackout, operators may now crosstie the HPCS diesel generator pump to a primary electrical train to power critical emergency systems. Another procedural change concerns the Firewater system. As recently modified (see Section 4.4.1), the Firewater system is currently included in plant emergency OPs as a source of emergency coolant injection. Prior to Firewater system modifications resulting from the NUREG-1150 analysis, Grand Gulf OPs did not include this system as an injection source.

While all of these changes are not quantified here, they have had the effect of lowering the overall core damage frequency at Grand Gulf.

4.4.3 High Pressure Core Spray Pump Assessment

The HPCS pump at Grand Gulf Unit 2 is a motor-driven and self-cooled unit that is provided with a dedicated diesel generator. A fraction of the water pumped by HPCS is circulated through the pump internals to cool the seals and bearings. These pump components could lose their integrity and fail if very high temperature water is circulated through the pump. This situation is only possible if two conditions are met: (1) the HPCS pump is drawing water from the suppression pool and (2) the pool temperature is increasing. The first condition occurs approximately one hour following a transient initiator and immediately following a LOCA initiator. The second condition is met when containment heat removal is lost, which occurs during station blackout sequences or sequences in which random failures of the containment heat removal systems occur.

In the original Grand Gulf NUREG/CR-4550 analysis [12], the analysts initially were unsure of the suppression pool temperature at which the HPCS pump seals and bearings would fail. An assumption was made that at 250°F the seals and bearings would fail and that the failure would be catastrophic. Updated information on the HPCS pump was utilized in the revised Grand Gulf analysis. Pump seals are assessed to fail at 250°F as in the original analysis, but leakage is postulated to result, not catastrophic failure. Examination of the systems and components at the plant in the vicinity of the HPCS pump revealed no potentially harmful consequences from pump seal leakage. Pump bearings were also given more credit for operation in a harsh environment than in the original analysis. Documents were obtained which show HPCS pump bearings are qualified for safe operation at 350°F for 24 hours. Thermal-hydraulic analyses indicate the peak suppression pool temperature prior to containment failure is approximately 280°F. Therefore, pump bearings were not assessed to fail in the revised analysis.

The new assessment of the HPCS pump has a significant effect on the quantitative results of the revised NUREG/CR-4550 analysis [11]. Many sequences that appeared in the original report did not appear in the revised report due to the HPCS pump assessment. Dominant sequences that were eliminated decreased the core damage frequency by 76% in the new draft report. Most of this decrease is due to elimination of station blackout sequences. The lone action of eliminating the event representing HPCS pump seal failure, HPCS-SEAL, decreased the CDF from 2.9E-5 to 7.0E-6.

5. SUMMARY AND CONCLUSIONS

The purpose of risk management programs is to reduce the public health risk and provide additional capability for reducing the probability and consequences of severe accidents. Risk management is a complex process that has been divided into five interrelated phases ranging from prevention of accident initiators to retention of fission products. This report has presented a general approach for using PRA-type analyses to supplement risk management programs in all five of the identified phases. This approach is possible as a result of the advances in PRA technology from the NUREG-1150 analyses. Further, while not addressed in detail in this report, uncertainties in the progression of severe accidents can be explicitly treated. This advanced PRA technology allows the in-depth, integrated treatment of all phases of severe accidents, although this could not be fully demonstrated in this limited-scope report.

The integrated treatment that PRA provides is necessary in order to deal with the complex interactions and synergistic effects that can result from a particular risk management action. Care must be taken to assure that risk management options that could reduce the core damage frequency do not increase overall risk by generating sequences with lower frequency but higher radioactive releases. The optimization of risk management strategies may vary, depending on the particular figure of merit selected. Actions to reduce health risks may not reduce economic risks and vice versa. It is also important to consider the interactions and tradeoffs among multiple risk management options. One example of an integrated strategy involving multiple options was included in this report.

The consideration of uncertainties is important in any program that deals with the analysis of severe accidents. The Three Mile Island accident and other incidents make it clear that prescriptive, deterministic analyses and procedures are not always appropriate. The NUREG-1150 methodology provides a framework for identifying and examining a wide range of potential outcomes and building flexibility into risk management strategies.

Due to resource constraints, this study has focused on the quantitative analysis of Phase 1 and Phase 2 risk management options (prior to core damage), with qualitative discussions of the other three phases. The particular results from this study are not as important as the demonstration of the approach and the future potential that it offers. The quantitative results presented here are extremely plant-specific and should not be assumed to represent the condition of risk management efforts within the nuclear industry.

Three particular areas have been examined in this study. These areas are: 1) the direct benefits of performing PRA studies, 2) the effectiveness of current risk management procedures, and 3) the evaluation of future risk management options. The NUREG-1150 methodology can be used to analyze each of these areas and gain insight into improvement of plant performance.

Generally, the performance of a PRA will directly impact the risk of the plant. Vulnerabilities are identified, and any unacceptable plant problems are quickly remedied by the plant's utility. Several examples of plant changes were discussed in the earlier chapters. Also, the PRA provides a much greater awareness by the plant staff of the range of outcomes that can result from severe accidents. This requires a concerted effort on the part of the PRA analyst to involve the plant staff in the study and inform them of the subsequent results, which can substantially improve the staff training programs.

All plants have some risk management capabilities in place, to the extent that they have emergency operating procedures and systems designed to mitigate severe accidents. This report has examined the efficacy of a few such systems and procedures. The evaluation of existing procedures is important to assure that unexpected adverse results will not occur during an accident. Often, procedures and hardware are altered to address a specific problem. The integrated risk analysis framework can be used to assure that unexpected interactions with other systems and during other portions of an accident do not result from the change.

The largest potential for using the methods outlined in this report is in the area of developing and evaluating future risk management capabilities. The nuclear industry has made great strides in managing accidents prior to core damage. However, much remains to be done for the later phases of an accident. It appears that the current industry approach of developing symptom-based, as opposed to event-based, procedures has been extremely successful and can be extended into the later stages of an accident. The NUREG-1150 methods can help provide a basis for selecting the symptoms to be included in such procedures, and thereby assist in defining information and instrumentation needs for monitoring the progress of severe accidents. Ultimately, alternative strategies can be evaluated and compared, and an optimal risk management program can be developed.

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DISTRIBUTION:

Frank Abbey
U. K. Atomic Energy Authority
Wigshaw Lane, Culcheth
Warrington, Cheshire, WA3 4NE
ENGLAND

Kiyoharu Abe
Department of Reactor Safety Research
Nuclear Safety Research Center
ToKai Research Establishment
JAERI
Tokai-mura, Naga-gun
Ibaraki-ken,
JAPAN

Ulvi Adalioglu
Nuclear Engineering Division
Cekmece Nuclear Research and Training Centre
P.K.1, Havaalani
Istanbul
TURKEY

Bharat Agrawal
USNRC-RES/AEB
MS: NL/N-344

Kiyoto Aizawa
Safety Research Group
Reactor Research and Development Project
PNC
9-13m 1-Chome Akasaka
Minatu-Ku
Tokyo
JAPAN

Oguz Akalin
Ontario Hydro
700 University Avenue
Toronto, Ontario
CANADA M5G 1X6

David Aldrich
Science Applications International Corporation
1710 Goodridge Drive
McLean, VA 22102

Agustin Alonso
University Politecnica De Madrid
J Gutierrez Abascal, 2
28006 Madrid
SPAIN

Christopher Amos
Science Applications International Corporation
2109 Air Park Road SE
Albuquerque, NM 87106

Richard C. Anoba
Project Engr., Corp. Nuclear Safety
Carolina Power and Light Co.
P. O. Box 1551
Raleigh, NC 27602

George Apostolakis
UCLA
Boelter Hall, Room 5532
Los Angeles, CA 90024

James W. Ashkar
Boston Edison Company
800 Boylston Street
Boston, MA 02199

Donald H. Ashton
Bechtel Power Corporation
15740 Shady Grove Road
Gaithersburg, MD 20877

J. de Assuncao
Cabinete de Proteccao e Seguranca Nuclear
Secretario de Estado de Energia
Ministerio da Industria
av. da Republica, 45-6°
1000 Lisbon
PORTUGAL

Mark Averett
Florida Power Corporation
P.O. Box 14042
St. Petersburg, FL 33733

Raymond O. Bagley
Northeast Utilities
P.O. Box 270
Hartford, CT 06141-0270

Juan Bagues
Consejo de Seguridad Nucleare
Sarangela de la Cruz 3
28020 Madrid
SPAIN

George F. Bailey
Washington Public Power Supply System
P. O. Box 968
Richland, WA 99352

H. Bairiot
Belgonucleaire S A
Rue de Champ de Mars 25
B-1050 Brussels
BELGIUM

Louis Baker
Reactor Analysis and Safety Division
Building 207
Argonne National Laboratory
9700 South Cass Avenue
Argonne, IL 60439

H-P. Balfanz
TUV-Norddeutschland
Grosse Bahnstrasse 31,
2000 Hamburg 54
FEDERAL REPUBLIC OF GERMANY

Patrick Baranowsky
USNRC-NRR/OEAB
MS: 11E-22

H. Bargmann
Dept. de Mecanique
Inst. de Machines Hydrauliques et de Mecaniques des Fluides
Ecole Polytechnique de Lausanne
CH-1003 Lausanne
M.E. (ECUBLENS)
CH. 1015 Lausanne
SWITZERLAND

Robert A. Bari
Brookhaven National Laboratory
Building 130
Upton, NY 11973

Richard Barrett
USNRC-NRR/PRAB
MS: 10A-2

Kenneth S. Baskin
S. California Edison Company
P.O. Box 800
Rosemead, CA 91770

J. Basselier
Belgonucleaire S A
Rue du Champ de Mars 25, B-1050
Brussels
BELGIUM

Werner Bastl
Gesellschaft Fur Reaktorsicherheit
Forschungsgelande
D-8046 Garching
FEDERAL REPUBLIC OF GERMANY

Anton Bayer
BGA/ISH/ZDB
Postfach 1108
D-8042 Neuherberg
FEDERAL REPUBLIC OF GERMANY

Ronald Bayer
Virginia Electric Power Co.
P. O. Box 26666
Richmond, VA 23261

Eric S. Beckjord
Director
USNRC-RES
MS: NL/S-007

Bruce B. Beckley
Public Service Company
P.O. Box 330
Manchester, NH 03105

William Beckner
USNRC-RES/SAIB
MS: NL/S-324

Robert M. Bernero
Director
USNRC-NMSS
MS: 6A-4

Ronald Berryman [2]
Virginia Electric Power Co.
P. O. Box 26666
Richmond, VA 23261

Robert C. Bertucio
NUS Corporation
1301 S. Central Ave, Suite 202
Kent, WA 98032

John H. Bickel
EG&G Idaho
P.O. Box 1625
Idaho Falls, ID 83415

Peter Bieniarz
Risk Management Association
2309 Dietz Farm Road, NW
Albuquerque, NM 87107

Adolf Birkhofer
Gesellschaft Fur Reaktorsicherheit
Forschungsgelande
D-8046 Garching
FEDERAL REPUBLIC OF GERMANY

James Blackburn
Illinois Dept. of Nuclear Safety
1035 Outer Park Drive
Springfield, IL 62704

Dennis C. Bley
Pickard, Lowe & Garrick, Inc.
2260 University Drive
Newport Beach, CA 92660

Roger M. Blond
Science Applications Int. Corp.
20030 Century Blvd., Suite 201
Germantown, MD 20874

Simon Board
Central Electricity Generating
Board
Technology and Planning Research
Division
Berkeley Nuclear Laboratory
Berkeley Gloucestershire, GL139PB
UNITED KINGDOM

Mario V. Bonace
Northeast Utilities Service Company
P.O. Box 270
Hartford, CT 06101

Gary J. Boyd
Safety and Reliability Optimization
Services
9724 Kingston Pike, Suite 102
Knoxville, TN 37922

Robert J. Breen
Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, CA 94303

Charles Brinkman
Combustion Engineering
7910 Woodmont Avenue
Bethesda, MD 20814

K. J. Brinkmann
Netherlands Energy Res. Fdtn.
P.O. Box 1
1755ZG Petten NH
NETHERLANDS

Allan R. Brown
Manager, Nuclear Systems and
Safety Department
Ontario Hydro
700 University Ave.
Toronto, Ontario M5G1X6
CANADA

Robert G. Brown
TENERA L.P.
1340 Saratoga-Sunnyvale Rd.
Suite 206
San Jose, CA 95129

Sharon Brown
EI Services
1851 So. Central Place, Suite 201
Kent, WA 98031

R. H. Buchholz
Nutech
6835 Via Del Oro
San Jose, CA 95119

Robert J. Budnitz
Future Resources Associates
734 Alameda
Berkeley, CA 94707

Gary R. Burdick
USNRC-RES/DSR
MS: NL/S-007

M. Bustraan
Netherlands Energy Res. Fdtn.
P.O. Box 1
1755ZG Petten NH
NETHERLANDS

Nigel E. Buttery
Central Electricity Generating Board
Booths Hall
Chelford Road, Knutsford
Cheshire, WA168QG
UNITED KINGDOM

Jose I. Calvo Molins
Probabilistic Safety Analysis Group
Consejo de Seguridad Nuclear
Sor Angela de la Cruz 3, Pl. 6
28020 Madrid
SPAIN

J. F. Campbell
Nuclear Installations Inspectorate
St. Peters House
Balliol Road, Bootle
Merseyside, L20 3LZ
UNITED KINGDOM

Kenneth S. Canady
Duke Power Company
422 S. Church Street
Charlotte, NC 28217

Lennart Carlsson
IAEA A-1400
Wagramerstrasse 5
P.O. Box 100
Vienna, 22
AUSTRIA

Annick Carnino
Electricite de France
32 Rue de Monceau 8EME
Paris, F5008
FRANCE

G. Caropreso
Dept. for Envir. Protect. & Hlth.
ENEA Cre Casaccia
Via Anguillarese, 301
00100 Roma
ITALY

James C. Carter, III
TENERA L.P.
Advantage Place
308 North Peters Road
Suite 280
Knoxville, TN 37922

Eric Cazzoli
Brookhaven National Laboratory
Building 130
Upton, NY 11973

John G. Cesare
SERI
Director Nuclear Licensing
5360 I-55 North
Jackson, MS 39211

S. Chakraborty
Radiation Protection Section
Div. De La Securite Des Inst. Nuc.
5303 Wurenlingen
SWITZERLAND

Sen-I Chang
Institute of Nuclear Energy Research
P.O. Box 3
Lungtan, 325
TAIWAN

J. R. Chapman
Yankee Atomic Electric Company
1671 Worcester Road
Framingham, MA 01701

Robert F. Christie
Tennessee Valley Authority
400 W. Summit Hill Avenue, W10D190
Knoxville, TN 37902

T. Cianciolo
BWR Assistant Director
ENEA DISP TX612167 ENEUR
Rome
ITALY

Thomas Cochran
Natural Resources Defense Council
1350 New York Ave. NW, Suite 300
Washington, D.C. 20005

Frank Coffman
USNRC-RES/HFB
MS: NL/N-316

Larry Conradi
NUS Corporation
16835 W. Bernardo Drive
Suite 202
San Diego, CA 92127

Peter Cooper
U.K. Atomic Energy Authority
Wigshaw Lane, Culcheth
Warrington, Cheshire, WA3 4NE
UNITED KINGDOM

C. Allin Cornell
110 Coquito Way
Portola Valley, CA 94025

Michael Corradini
University of Wisconsin
1500 Johnson Drive
Madison, WI 53706

E. R. Corran
Nuclear Technology Division
ANSTO Research Establishment
Lucas Heights Research Laboratories
Private Mail Bag 7
Menai, NSW 2234
AUSTRALIA

James Costello
USNRC-RES/SSEB
MS: NL/S-217A

George R. Crane
1570 E. Hobble Creek Dr.
Springville, UT 84663

Mat Crawford
SERI
5360 I-55 North
Jackson, MS 39211

Michael C. Cullingford
Nuclear Safety Division
IAEA
Wagramerstrasse, 5
P.O. Box 100
A-1400 Vienna
AUSTRIA

Garth Cummings
Lawrence Livermore Laboratory
L-91, Box 808
Livermore, CA 94526

Mark A. Cunningham
USNRC-RES/PRAB
MS: NL/S-372

James J. Curry
7135 Salem Park Circle
Mechanicsburg, PA 17055

Peter Cybulskis
Battelle Columbus Division
505 King Avenue
Columbus, OH 43201

Peter R. Davis
PRD Consulting
1935 Sabin Drive
Idaho Falls, ID 83401

Jose E. DeCarlos
Consejo de Seguridad Nuclear
Sor Angela de la Cruz 3, Pl. 8
28016 Madrid
SPAIN

M. Marc Decreton
Department Technologie
CEN/SCK
Boeretang 200
B-2400 Mol
BELGIUM

Richard S. Denning
Battelle Columbus Division
505 King Avenue
Columbus, OH 43201

Vernon Denny
Science Applications Int. Corp.
5150 El Camino Real, Suite 3
Los Altos, CA 94303

J. Devooget
Faculte des Sciences Appliques
Universite Libre de Bruxelles
av. Franklin Roosevelt
B-1050 Bruxelles
BELGIUM

R. A. Diederich
Supervising Engineer
Environmental Branch
Philadelphia Electric Co.
2301 Market St.
Philadelphia, PA 19101

Raymond DiSalvo
Battelle Columbus Division
505 King Avenue
Columbus, OH 43201

Mary T. Drouin
Science Applications International
Corporation
2109 Air Park Road S.E.
Albuquerque, NM 87106

Andrzej Drozd
Stone and Webster
Engineering Corp.
243 Summer Street
Boston, MA 02107

N. W. Edwards
NUTECH
145 Martinville Lane
San Jose, CA 95119

Ward Edwards
Social Sciences Research Institute
University of Southern California
Los Angeles, CA 90089-1111

Joachim Ehrhardt
Kernforschungszentrum Karlsruhe/INR
Postfach 3640
D-7500 Karlsruhe 1
FEDERAL REPUBLIC OF GERMANY

Adel A. El-Bassioni
USNRC-NRR/PRAB
MS: 10A-2

J. Mark Elliott
International Energy Associates,
Ltd., Suite 600
600 New Hampshire Ave., NW
Washington, DC 20037

Farouk Eltawila
USNRC-RES/AEB
MS: NL/N-344

Mike Epstein
Fauske and Associates
P. O. Box 1625
16W070 West 83rd Street
Burr Ridge, IL 60521

Malcolm L. Ernst
USNRC-RGN II

F. R. Farmer
The Long Wood, Lyons Lane
Appleton, Warrington
WA4 5ND
UNITED KINGDOM

P. Fehrenback
Atomic Energy of Canada, Ltd.
Chalk River Nuclear Laboratories
Chalk River Ontario, K0J1P0
CANADA

P. Ficara
ENEA Cre Casaccia
Department for Thermal Reactors
Via Anguillarese, 301
00100 ROMA
ITALY

A. Fiege
Kernforschungszentrum
Postfach 3640
D-7500 Karlsruhe
FEDERAL REPUBLIC OF GERMANY

John Flack
USNRC-RES/SAIB
MS: NLS-324

George F. Flanagan
Oak Ridge National Laboratory
P.O. Box Y
Oak Ridge, TN 37831

Karl N. Fleming
Pickard, Lowe & Garrick, Inc.
2260 University Drive
Newport Beach, CA 92660

Joseph R. Fragola
Science Applications International
Corporation
274 Madison Avenue
New York, NY 10016

Wiktor Frid
Swedish Nuclear Power Inspectorate
Division of Reactor Technology
P. O. Box 27106
S-102 52 Stockholm
SWEDEN

James Fulford
NUS Corporation
910 Clopper Road
Gaithersburg, MD 20878

Urho Fulkkinen
Technical Research Centre of
Finland
Electrical Engineering Laboratory
Otakaari 7 B
SF-02150 Espoo 15
FINLAND

J. B. Fussell
JBF Associates, Inc.
1630 Downtown West Boulevard
Knoxville, TN 37919

John Garrick
Pickard, Lowe & Garrick, Inc.
2260 University Drive
Newport Beach, CA 92660

John Gaunt
British Embassy
3100 Massachusetts Avenue, NW
Washington, DC 20008

Jim Gieseke
Battelle Columbus Division
505 King Avenue
Columbus, OH 43201

Frank P. Gillespie
USNRC-NRR/PMAS
MS: 12G-18

Ted Ginsburg
Department of Nuclear Energy
Building 820
Brookhaven National Laboratory
Upton, NY 11973

James C. Glynn
USNRC-RES/PRAB
MS: NL/S-372

P. Govaerts
Departement de la Surete Nucleaire
Association Vincotte
avenue du Roi 157
B-1060 Bruxelles
BELGIUM

George Greene
Building 820M
Brookhaven National Laboratory
Upton, NY 11973

Carrie Grimshaw
Brookhaven National Laboratory
Building 130
Upton, NY 11973

H. J. Van Grol
Energy Technology Division
Energieonderzoek Centrum Nederland
Westerduinweg 3
Postbus 1
NL-1755 Petten ZG
NETHERLANDS

Sergio Guarro
Lawrence Livermore Laboratories
P. O. Box 808
Livermore, CA 94550

Sigfried Hagen
Kernforschungzentrum Karlsruhe
P. O. Box 3640
D-7500 Karlsruhe 1
FEDERAL REPUBLIC OF GERMANY

L. Hammar
Statens Karnkraftinspektion
P.O. Box 27106
S-10252 Stockholm
SWEDEN

Stephen Hanauer
Technical Analysis Corp.
6723 Whittier Avenue
Suite 202
McLean, VA 22101

Brad Hardin
USNRC-RES/TRAB
MS: NL/S-169

R. J. Hardwich, Jr.
Virginia Electric Power Co.
P.O. Box 26666
Richmond, Va 23261

Michael R. Haynes
UKAEA Harwell Laboratory
Oxfordshire
Didcot, Oxon., OX11 ORA
ENGLAND

Michael J. Hazzan
Stone & Webster
3 Executive Campus
Cherry Hill, NJ 08034

A. Hedgran
Royal Institute of Technology
Nuclear Safety Department
Bunellvagen 60
10044 Stockholm
SWEDEN

Jon C. Helton
Dept. of Mathematics
Arizona State University
Tempe, AZ 85287

Robert E. Henry
Fauske and Associates, Inc.
16W070 West 83rd Street
Burr Ridge, IL 60521

P. M. Herttrich
Federal Ministry for the
Environment, Preservation of
Nature and Reactor Safety
Husarenstrasse 30
Postfach 120629
D-5300 Bonn 1
FEDERAL REPUBLIC OF GERMANY

F. Heuser
Giesellschaft Fur Reaktorsicherheit
Forschurgsgelande
D-8046 Garching
FEDERAL REPUBLIC OF GERMANY

E. F. Hicken
Giesellschaft Fur Reaktorsicherheit
Forschungsgelande
D-8046 Garching
FEDERAL REPUBLIC OF GERMANY

D. J. Higson
Radiological Support Group
Nuclear Safety Bureau
Australian Nuclear Science and
Technology Organisation
P.O. Box 153
Rosebery, NSW 2018
AUSTRALIA

Daniel Hirsch
University of California
A. Stevenson Program on
Nuclear Policy
Santa Cruz, CA 95064

H. Hirschmann
Hauptabteilung Sicherheit und
Umwelt
Swiss Federal Institute for
Reactor Research (EIR)
CH-5303 Wurenlingen
SWITZERLAND

Mike Hitchler
Westinghouse Electric Corp.
Savanna River Site
Aiken, SC 29808

Richard Hobbins
EG&G Idaho
P. O. Box 1625
Idaho Falls, ID 83415

Steven Hodge
Oak Ridge National Laboratory
P.O. Box Y
Oak Ridge, TN 37831

Lars Hoegberg
Office of Regulation and Research
Swedish Nuclear Power Inspectorate
P. O. Box 27106
S-102 52 Stockholm
SWEDEN

Lars Hoeghort
IAEA A-1400
Wagranerstraase 5
P.O. Box 100
Vienna, 22
AUSTRIA

Edward Hofer
Giesellschaft Fur Reaktorsicherheit
Forschurgsgelande
D-8046 Garching
FEDERAL REPUBLIC OF GERMANY

Peter Hoffmann
Kernforschingszentrum Karlsruhe
Institute for Material
Und Festkorperforsching I
Postfach 3640
D-7500 Karlsruhe 1
FEDERAL REPUBLIC OF GERMANY

N. J. Holloway
UKAEA Safety and Reliability
Directorate
Wigshaw Lane, Culcheth
Warrington, Cheshire, WA34NE
UNITED KINGDOM

Stephen C. Hora
University of Hawaii at Hilo
Division of Business Administration
and Economics
College of Arts and Sciences
Hilo, HI 96720-4091

J. Peter Hoseman
Swiss Federal Institute for
Reactor Research
CH-5303, Wurenlingen
SWITZERLAND

Thomas C. Houghton
KMC, Inc.
1747 Pennsylvania Avenue, NW
Washington, DC 20006

Dean Houston
USNRC-ACRS
MS: P-315

Der Yu Hsia
Taiwan Atomic Energy Council
67, Lane 144, Keelung Rd.
Sec. 4
Taipei
TAIWAN

Alejandro Huerta-Bahena
National Commission on Nuclear
Safety and Safeguards (CNSNS)
Insurgentes Sur N. 1776
Col. Florida
C. P. 04230 Mexico, D.F.
MEXICO

Kenneth Hughey [2]
SERI
5360 I-55 North
Jackson, MS 39211

Won-Guk Hwang
Kzunghee University
Yongin-Kun
Kyunggi-Do 170-23
KOREA

Michio Ichikawa
Japan Atomic Energy Research
Institute
Dept. of Fuel Safety Research
Tokai-Mura, Naka-Gun
Ibaraki-Ken, 319-1
JAPAN

Sanford Israel
USNRC-AEOD/ROAB
MS: MNBB-9715

Krishna R. Iyengar
Louisiana Power and Light
200 A Huey P. Long Avenue
Gretna, LA 70053

R. E. Jaquith
Combustion Engineering, Inc.
1000 Prospect Hill Road
M/C 9490-2405
Windsor, CT 06095

S. E. Jensen
Exxon Nuclear Company
2101 Horn Rapids Road
Richland, WA 99352

Kjell Johannson
Studsvik Energiteknik AB
S-611 82, Nykoping
SWEDEN

Richard John
SSM, Room 102
927 W. 35th Place
USC, University Park
Los Angeles, CA 90089-0021

D. H. Johnson
Pickard, Lowe & Garrick, Inc.
2260 University Drive
Newport Beach, CA 92660

W. Reed Johnson
Department of Nuclear Engineering
University of Virginia
Reactor Facility
Charlottesville, VA 22901

Jeffery Julius
NUS Corporation
1301 S. Central Ave, Suite 202
Kent, WA 98032

H. R. Jun
Korea Adv. Energy Research Inst.
P.O. Box 7, Daeduk Danju
Chungnam 300-31
KOREA

Peter Kafka
Gesellschaft Fur Reaktorsicherheit
Forschungsgelande
D-8046 Garching
FEDERAL REPUBLIC OF GERMANY

Geoffrey D. Kaiser
Science Application Int. Corp.
1710 Goodridge Drive
McLean, VA 22102

William Kastenberg
UCLA
Boelter Hall, Room 5532
Los Angeles, CA 90024

Walter Kato
Brookhaven National Laboratory
Associated Universities, Inc.
Upton, NY 11973

M. S. Kazimi
MIT, 24-219
Cambridge, MA 02139

Ralph L. Keeney
101 Lombard Street
Suite 704W
San Francisco, CA 94111

Henry Kendall
Executive Director
Union of Concerned Scientists
Cambridge, MA

Frank King
Ontario Hydro
700 University Avenue
Bldg. H11 G5
Toronto
CANADA M5G1X6

Oliver D. Kingsley, Jr.
Tennessee Valley Authority
1101 Market Street
GN-38A Lookout Place
Chattanooga, TN 37402

Stephen R. Kinnersly
Winfrith Atomic Energy
Establishment
Reactor Systems Analysis Division
Winfrith, Dorchester
Dorset DT2 8DH
ENGLAND

Ryohel Kiyose
University of Tokyo
Dept. of Nuclear Engineering
7-3-1 Hongo Bunkyo
Tokyo 113
JAPAN

George Klopp
Commonwealth Edison Company
P.O. Box 767, Room 35W
Chicago, IL 60690

Klaus Koberlein
Gesellschaft Fur Reaktorsicherheit
Forschungsgelande
D-8046 Garching
FEDERAL REPUBLIC OF GERMANY

E. Kohn
Atomic Energy Canada Ltd.
Candu Operations
Mississauga
Ontario, L5K 1B2
CANADA

Alan M. Kolaczkowski
Science Applications International Corporation
2109 Air Park Road, S.E.
Albuquerque, NM 87106

S. Kondo
Department of Nuclear Engineering
Facility of Engineering
University of Tokyo
3-1, Hongo 7, Bunkyo-ku
Tokyo
JAPAN

Herbert J. C. Kouts
Brookhaven National Laboratory
Building 179C
Upton, NY 11973

Thomas Kress
Oak Ridge National Laboratory
P.O. Box Y
Oak Ridge, TN 37831

W. Kroger
Institut fur Nukleare Sicherheitsforschung
Kernforschungsanlage Julich GmbH
Postfach 1913
D-5170 Julich 1
FEDERAL REPUBLIC OF GERMANY

Greg Krueger [3]
Philadelphia Electric Co.
2301 Market St.
Philadelphia, PA 19101

Bernhard Kuczera
Kernforschungzentrum Karlsruhe
LWR Safety Project Group (PRS)
P. O. Box 3640
D-7500 Karlsruhe 1
FEDERAL REPUBLIC OF GERMANY

Jeffrey L. LaChance
Science Applications International Corporation
2109 Air Park Road S.E.
Albuquerque, NM 87106

H. Larsen
Riso National Laboratory
Postbox 49
DK-4000 Roskilde
DENMARK

Wang L. Lau
Tennessee Valley Authority
400 West Summit Hill Avenue
Knoxville, TN 37902

Timothy J. Leahy
EI Services
1851 South Central Place, Suite 201
Kent, WA 98031

John C. Lee
University of Michigan
North Campus
Dept. of Nuclear Engineering
Ann Arbor, MI 48109

Tim Lee
USNRC-RES/RPSB
MS: NL/N-353

Mark T. Leonard
Science Applications International Corporation
2109 Air Park Road, SE
Albuquerque, NM 87106

Leo LeSage
Director, Applied Physics Div.
Argonne National Laboratory
Building 208, 9700 South Cass Ave.
Argonne, IL 60439

Milton Levenson
Bechtel Western Power Company
50 Beale St.
San Francisco, CA 94119

Librarian
NUMARC/USCEA
1776 I Street NW, Suite 400
Washington, DC 80006

Eng Lin
Taiwan Power Company
242, Roosevelt Rd., Sec. 3
Taipei
TAIWAN

N. J. Liparulo
Westinghouse Electric Corp.
P. O. Box 355
Pittsburgh, PA 15230

Y. H. (Ben) Liu
Department of Mechanical Engineering
University of Minnesota
Minneapolis, MN 55455

Bo Liwnang
IAEA A-1400
Swedish Nuclear Power Inspectorate
P.O. Box 27106
S-102 52 Stockholm
SWEDEN

J. P. Longworth
Central Electric Generating Board
Berkeley Gloucester
GL13 9PB
UNITED KINGDOM

Walter Lowenstein
Electric Power Research Institute
3412 Hillview Avenue
P. O. Box 10412
Palo Alto, CA 94303

William J. Luckas
Brookhaven National Laboratory
Building 130
Upton, NY 11973

Hans Ludewig
Brookhaven National Laboratory
Building 130
Upton, NY 11973

Robert J. Lutz, Jr.
Westinghouse Electric Corporation
Monroeville Energy Center
EC-E-371, P. O. Box 355
Pittsburgh, PA 15230-0355

Phillip E. MacDonald
EG&G Idaho, Inc.
P.O. Box 1625
Idaho Falls, ID 83415

Jim Mackenzie
World Resources Institute
1735 New York Ave. NW
Washington, DC 20006

A. P. Malinauskas
Oak Ridge National Laboratory
P.O. Box Y
Oak Ridge, TN 37831

Giuseppe Mancini
Commission European Comm.
CEC-JRC Eraton
Ispra Varese
ITALY

Lasse Mattila
Technical Research Centre of Finland
Lonnrotinkatu 37, P. O. Box 169
SF-00181 Helsinki 18
FINLAND

Roger J. Mattson
SCIENTECH Inc.
11821 Parklawn Dr.
Rockville, MD 20852

Donald McPherson
USNRC-NRR/DONRR
MS: 12G-18

Jim Metcalf
Stone and Webster Engineering Corporation
245 Summer St.
Boston, MA 02107

Mary Meyer
A-1, MS F600
Los Alamos National Laboratory
Los Alamos, NM 87545

Ralph Meyer
USNRC-RES/AEB
MS: NL/N-344

Charles Miller
8 Hastings Rd.
Momsey, NY 10952

Joseph Miller
Gulf States Utilities
P. O. Box 220
St. Francisville, LA 70775

William Mims
Tennessee Valley Authority
400 West Summit Hill Drive.
W10D199C-K
Knoxville, TN 37902

Jocelyn Mitchell
USNRC-RES/SAIB
MS: NL/S-324

Kam Mohktarian
CBI Na-Con Inc.
800 Jorie Blvd.
Oak Brook, IL 60521

S. Mori
Nuclear Safety Division
OECD Nuclear Energy Agency
38 Blvd. Suchet
75016 Paris
FRANCE

Walter B. Murfin
P.O. Box 550
Mesquite, NM 88048

Joseph A. Murphy
USNRC-RES/DSR
MS: NL/S-007

V. I. Nath
Safety Branch
Safety Engineering Group
Sheridan Park Research Community
Mississauga, Ontario L5K 1B2
CANADA

Susan J. Niemczyk
1545 18th St. NW, #112
Washington, DC 20036

P. K. Niyogi
USNRC-RES/PRAB
MS: NL/S-372

Paul North
EG&G Idaho, Inc.
P. O. Box 1625
Idaho Falls, ID 83415

Edward P. O'Donnell
Ebasco Services, Inc.
2 World Trade Center, 89th Floor
New York, NY 10048

David Okrent
UCLA
Boelter Hall, Room 5532
Los Angeles, CA 90024

Robert L. Olson
Tennessee Valley Authority
400 West Summit Hill Rd.
Knoxville, TN 37902

Simon Ostrach
Case Western Reserve University
418 Glenman Bldg.
Cleveland, OH 44106

D. Paddleford
Westinghouse Electric Corporation
Savanna River Site
Aiken, SC 29808

Robert L. Palla, Jr.
USNRC-NRR/PRAB
MS: 10A-2

Chang K. Park
Brookhaven National Laboratory
Building 130
Upton, NY 11973

Michael C. Parker
Illinois Department of Nuclear
Safety
1035 Outer Park Dr.
Springfield, IL 62704

Gareth Parry
NUS Corporation
910 Clopper Road
Gaithersburg, MD 20878

J. Pelce
Departement de Surete Nucleaire
IPSN
Centre d'Estudes Nucleaires du CEA
B.P. no. 6, Cedex
F-92260 Fontenay-aux-Roses
FRANCE

G. Petrangeli
ENEA Nuclear Energy ALT Disp
Via V. Brancati, 48
00144 Rome
ITALY

Marty Plys
Fauske and Associates
16W070 West 83rd St.
Burr Ridge, IL 60521

Mike Podowski
Department of Nuclear Engineering
and Engineering Physics
RPI
Troy, NY 12180-3590

Robert D. Pollard
Union of Concerned Scientists
1616 P Street, NW, Suite 310
Washington, DC 20036

R. Potter
UK Atomic Energy Authority
Winfrith, Dorchester
Dorset, DT2 8DH
UNITED KINGDOM

William T. Pratt
Brookhaven National Laboratory
Building 130
Upton, NY 11973

M. Preat
Chef du Service Surete Nucleaire et
Assurance Qualite
TRACTEBEL
Bd. du Regent 8
B-100 Bruxells
BELGIUM

David Pyatt
USDOE
MS: EH-332
Washington, DC 20545

William Raisin
NUMAEC
1726 M St. NW
Suite 904
Washington, DC 20036

Joe Rashid
ANATECH Research Corp.
3344 N. Torrey Pines Ct.
Suite 1320
La Jolla, CA 90237

Dale M. Rasmuson
USNRC-RES/PRAB
MS: NL/S-372

Ingvard Rasmussen
Riso National Laboratory
Postbox 49
DK-4000, Roskilde
DENMARK

Norman C. Rasmussen
Massachusetts Institute of
Technology
77 Massachusetts Avenue
Cambridge, MA 02139

John W. Reed
Jack R. Benjamin & Associates, Inc.
444 Castro St., Suite 501
Mountain View, CA 94041

David B. Rhodes
Atomic Energy of Canada, Ltd.
Chalk River Nuclear Laboratories
Chalk River, Ontario K0J1P0
CANADA

Dennis Richardon
Westinghouse Electric Corporation
P.O. Box 355
Pittsburgh, PA 15230

Doug Richeard
Virginia Electric Power Co.
P.O.Box 26666
Richmond, VA 23261

Robert Ritzman
Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, CA 94304

Richard Robinson
USNRC-RES/PRAB
MS: NL/S-372

Jack E. Rosenthal
USNRC-AEOD/ROAB
MS: MNBB-9715

Denwood F. Ross
USNRC-RES
MS: NL/S-007

Frank Rowsome
9532 Fern Hollow Way
Gaithersburg, MD 20879

Wayne Russell
SERI
5360 I-55 North
Jackson, MS 39211

Jorma V. Sandberg
Finnish Ctr. Rad. Nucl. and Safety
Department of Nuclear Safety
P.O. Box 268
SF-00101 Helsinki
FINLAND

G. Saponaro
ENEA Nuclear Engineering Alt.
Zia V Brancati 4B
00144 ROME
ITALY

M. Sarran
United Engineers
P. O. Box 8223
30 S 17th Street
Philadelphia, PA 19101

Marty Sattison
EG&G Idaho
P. O. Box 1625
Idaho Falls, ID 83415

George D. Sauter
Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, CA 94303

Jorge Schulz
Bechtel Western Power Corporation
50 Beale Street
San Francisco, CA 94119

B. R. Sehgal
Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, CA 94303

Subir Sen
Bechtel Power Corp.
15740 Shady Grove Road
Location 1A-7
Gaithersburg, MD 20877

S. Serra
Ente Nazionale per l'Energia
Electtrica (ENEL)
via G. B. Martini 3
Rome
ITALY

Bonnie J. Shapiro
Science Applications International
Corporation
802 East Martintown Rd.
Suite 208
North Augusta, SC 29841

H. Shapiro
Licensing and Risk Branch
Atomic Energy of Canada Ltd.
Sheridan Park Research Community
Mississauga, Ontario L5K 1B2
CANADA

John Sherman
Tennessee Environmental Council
1719 West End Avenue, Suite 227
Nashville, TN 37203

Brian Sheron
USNRC-RES/DSR
MS: NL/N-007

Rick Sherry
JAYCOR
P. O. Box 85154
San Diego, CA 92138

Steven C. Sholly
MHB Technical Associates
1723 Hamilton Avenue, Suite K
San Jose, CA 95125

Louis M. Shotkin
USNRC-RES/RPSB
MS: NL/N-353

M. Siebertz
Chef de la Section Surete' des
Reacteurs
CEN/SCK
Boeretang, 200
B-2400 Mol
BELGIUM

Melvin Silberberg
USNRC-RES/DE/WNB
MS: NL/S-260

Gary Smith
SERI
5360 I-55 North
Jackson, MS 39211

Gary L. Smith
Westinghouse Electric Corporation
Hanford Site
Box 1970
Richland, WA 99352

Lanny N. Smith
Science Applications International
Corporation
2109 Air Park Road SE
Albuquerque, NM 87106

K. Soda
Japan Atomic Energy Res. Inst.
Tokai-Mura Naka-Gun
Ibaraki-Ken 319-11
JAPAN

Leonard Soffer
USNRC-RES/SAIB
MS: NL/S-324

David Sommers
Virginia Electric Power Company
P. O. Box 26666
Richmond, VA 23261

Herschel Spector
New York Power Authority
123 Main Street
White Plains, NY 10601

Themis P. Speis
USNRC-RES
MS: NL/S-007

Klaus B. Stadie
OECD-NEA, 38 Bld. Suchet
75016 Paris
FRANCE

John Stetkar
Pickard, Lowe & Garrick, Inc.
2216 University Drive
Newport Beach, CA 92660

Wayne L. Stiede
Commonwealth Edison Company
P.O. Box 767
Chicago, IL 60690

William Stratton
Stratton & Associates
2 Acoma Lane
Los Alamos, NM 87544

Soo-Pong Suk
Korea Advanced Energy Research
Institute
P. O. Box 7
Daeduk Danji, Chungnam 300-31
KOREA

W. P. Sullivan
GE Nuclear Energy
175 Curtner Ave., M/C 789
San Jose, CA 95125

Tony Taig
U.K. Atomic Energy Authority
Wigshaw Lane, Culcheth
Warrington, Cheshire, WA3 4NE
UNITED KINGDOM

John Taylor
Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, CA 94303

Harry Teague
U.K. Atomic Energy Authority
Wigshaw Lane, Culcheth
Warrington, Cheshire, WA3 4NE
UNITED KINGDOM

Technical Library
Electric Power Research Institute
P.O. Box 10412
Palo Alto, CA 94304

Mark I. Temme
General Electric, Inc.
P.O. Box 3508
Sunnyvale, CA 94088

T. G. Theofanous
University of California, S.B.
Department of Chemical and Nuclear Engineering
Santa Barbara, CA 93106

David Teolis
Westinghouse-Bettis Atomic Power Laboratory
P. O. Box 79, ZAP 34N
West Mifflin, PA 15122-0079

Ashok C. Thadani
USNRC-NRR/SAD
MS: 7E-4

Garry Thomas
L-499 (Bldg. 490)
Lawrence Livermore National Laboratory
7000 East Ave.
P.O. Box 808
Livermore, CA 94550

Gordon Thompson
Institute for Research and Security Studies
27 Ellworth Avenue
Cambridge, MA 02139

Grant Thompson
League of Women Voters
1730 M. Street, NW
Washington, DC 20036

Arthur Tingle
Brookhaven National Laboratory
Building 130
Upton, NY 11973

Rich Toland
United Engineers and Construction
30 S. 17th St., MS 4V7
Philadelphia, PA 19101

Brian J. R. Tolley
DG/XII/D/1
Commission of the European Communities
Rue de la Loi, 200
B-1049 Brussels
BELGIUM

David R. Torgerson
Atomic Energy of Canada Ltd.
Whiteshell Nuclear Research Establishment
Pinawa, Manitoba, ROE 1LO
CANADA

Alfred F. Torri
Pickard, Lowe & Garrick, Inc.
191 Calle Magdalena, Suite 290
Encinitas, CA 92024

Klau Trambauer
Gesellschaft Fur Reaktorsicherheit
Forschungsgelande
D-8046 Garching
FERERAL REPUBLIC OF GERMANY

Nicholas Tsoulfanidis
Nuclear Engineering Dept.
University of Missouri-Rolla
Rolla, MO 65401-0249

Chao-Chin Tung
c/o H.B. Bengelsdorf
ERC Environmental Services Co.
P. O. Box 10130
Fairfax, VA 22030

Brian D. Turland
UKAEA Culham Laboratory
Abingdon, Oxon OX14 3DB
ENGLAND

Takeo Uga
Japan Institute of Nuclear Safety
Nuclear Power Engineering Test Center
3-6-2, Toranomon
Minato-ku, Tokyo 108
JAPAN

Stephen D. Unwin
Battelle Columbus Division
505 King Avenue
Columbus, OH 43201

A. Valeri
DISP
ENEA
Via Vitaliano Brancati, 48
I-00144 Rome
ITALY

Harold VanderMolen
USNRC-RES/PRAB
MS: NL/S-372

G. Bruce Varnado
ERC International
1717 Louisiana Blvd. NE, Suite 202
Albuquerque, NM 87110

Jussi K. Vaurio
Imatran Voima Oy
Loviisa NPS
SF-07900 Loviisa
FINLAND

William E. Vesely
Science Applications International Corporation
2929 Kenny Road, Suite 245
Columbus, OH 43221

J. I. Villadoniga Tallon
Div. of Analysis and Assessment
Consejo de Seguridad Nuclear
c/ Sor Angela de la Cruz, 3
28020 Madrid
SPAIN

Willem F. Vinck
Kapellestract 25
1980
Tervuren
BELGIUM

R. Virolainen
Office of Systems Integration
Finnish Centre for Radiation and Nuclear Safety
Department of Nuclear Safety
P.O. Box 268
Kumpulantie 7
SF-00520 Helsinki
FINLAND

Raymond Viskanta
School of Mechanical Engineering
Purdue University
West Lafayette, IN 47907

S. Visweswaran
General Electric Company
175 Curtner Avenue
San Jose, CA 95125

Truong Vo
Pacific Northwest Laboratory
Battelle Blvd.
Richland, WA 99352

Richard Vogel
Electric Power Research Institute
P. O. Box 10412
Palo Alto, CA 94303

G. Volta
Engineering Division
CEC Joint Research Centre
CP No. 1
I-21020 Ispra (Varese)
ITALY

Ian B. Wall
Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, CA 94303

Adolf Walser
Sargent and Lundy Engineers
55 E. Monroe Street
Chicago, IL 60603

Edward Warman
Stone & Webster Engineering Corp.
P.O. Box 2325
Boston, MA 02107

Norman Weber
Sargent & Lundy Co.
55 E. Monroe Street
Chicago, IL 60603

Lois Webster
American Nuclear Society
555 N. Kensington Avenue
La Grange Park, IL 60525

Wolfgang Werner
Gesellschaft Fur Reaktorsicherheit
Forschungsgelande
D-8046 Garching
FEDERAL REPUBLIC OF GERMANY

Don Wesley
IMPELL
1651 East 4th Street
Suite 210
Santa Ana, CA 92701

Detlof von Winterfeldt
Institute of Safety and Systems
Management
University of Southern California
Los Angeles, CA 90089-0021

Pat Worthington
USNRC-RES/AEB
MS: NL/N-344

John Wreathall
Science Applications International
Corporation
2929 Kenny Road, Suite 245
Columbus, OH 43221

D. J. Wren
Atomic Energy of Canada Ltd.
Whiteshell Nuclear Research
Establishment
Pinawa, Manitoba, ROE 1LO
CANADA

Roger Wyrick
Inst. for Nuclear Power Operations
1100 Circle 75 Parkway, Suite 1500
Atlanta, GA 30339

Kun-Joong Yoo
Korea Advanced Energy Research
Institute
P. O. Box 7
Daeduk Danji, Chungnam 300-31
KOREA

Faith Young
Energy People, Inc.
Dixou Springs, TN 37057

Jonathan Young
R. Lynette and Associates
15042 Northeast 40th St.
Suite 206
Redmond, WA 98052

C. Zaffiro
Division of Safety Studies
Directorate for Nuclear Safety and
Health Protection
Ente Nazionale Energie Alternative
Via Vitaliano Brancati, 48
I-00144 Rome
ITALY

X. Zikidis
Greek Atomic Energy Commission
Agia Paraskevi, Attiki
Athens
GREECE

Bernhard Zuczera
Kernforschungszentrum
Postfach 3640
D-7500 Karlsruhe
FEDERAL REPUBLIC OF GERMANY

1521 J. R. Weatherby
3141 S. A. Landenberger [5]
3151 W. I. Klein
6400 D. J. McCloskey
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9144 A. S. Benjamin

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This report describes the potential uses of NUREG-1150 and similar Probabilistic Risk Assessments (PRAs) in NRC and industry risk management programs. NUREG-1150 uses state-of-the-art PRA techniques to estimate the risk from five nuclear power plants. The methods and results produced in NUREG-1150 provide a framework within which current risk management strategies can be evaluated, and future risk management programs can be developed and assessed. While the development of plant-specific risk management strategies is beyond the scope of this document, examples of the use of the NUREG-1150 framework for identifying and evaluating risk management options are presented. All phases of risk management from prevention of initiating events through reduction of off-site consequences are discussed, with particular attention given to the early phases of accidents.

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