PRAIRIE ISLAND

INDIVIDUAL PLANT EXAMINATION OF EXTERNAL EVENTS (IPEEE)

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Revision 0

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EXECUTIVE SUMMARY

This report documents Northern States Power Company's (NSP) response to Supplement 4 of Generic Letter (GL) 88-20, "Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities", which was issued in June of 1991. The IPEEE extends the analysis performed for the Individual Plant Examination of internal events (IPE) which is the subject of the Generic Letter and its first three supplements. NSP's IPE report for the Prairie Island plant was submitted to the NRC for review on March 1, 1994.

The IPEEE assessments described in this report address the external events identified in Supplement 4 of GL 88-20, namely earthquakes (seismic activity), internal fires, high winds, floods, and other credible external events. For the seismic investigation, NSP elected to complete the Prairie Island seismic IPEEE by conducting the equivalent of a reduced scope seismic margins assessment with an additional focus on a few key components, in accordance with Supplement 5 of Generic Letter 88-20. NSP determined that the internal fire assessment could best be done with a PRA approach using the updated IPE models, combined with the deterministic evaluation techniques of the EPRI Fire Induced Vulnerabilities Evaluation (FIVE) Methodology. The evaluation of other external events was performed using a combination of probabilistic and deterministic techniques. The analyses for these assessments began in 1994.

The attached report summarizes the results of the assessments conducted to consider the potential for severe accident vulnerabilities due to the set of external events identified by Generic Letter 88-20, Supplement 4. Based on this report, it is concluded that there are no significant vulnerabilities to severe accidents that exist at Prairie Island that would be attributable to seismic, fire, or other external events. This report completes commitments made in regard to the Generic Letter with respect to the IPEEE.

1. EXAMINATION DESCRIPTION

1.1 Introduction

In July and August of 1985, the NRC published its policy statement on issues related to severe accidents in NUREG-1070 and 10 CFR Part 50. The Severe Accident Policy states that, on the basis of currently available information, existing plants pose "no undue risk" to the health and safety of the public. Therefore, the NRC sees no justification to take immediate action on generic rule making or other regulatory changes for existing plants because of issues related to severe accidents. The Commission's conclusion of "no undue risk" is based upon actions taken as a result of the Three Mile Island action plan (NUREG-0737), information that resulted from NRC and industry-sponsored research, information obtained from published Probabilistic Risk Assessments (PRAs) and operating experience, and the results of the Industry Degraded Core Rulemaking Committee (IDCOR) technical program.

Since November, 1988, the NRC staff issued Generic Letter 88-20 and five supplements which formalized the requirement for an Individual Plant Examination (IPE) under 10 CFR 50.54(f). This generic letter requested utilities to perform their IPEs, provided reporting requirements (Supplement 1), identified accident management strategies to be considered as part of the IPE (Supplement 2) and established containment performance improvement considerations (Supplement 3). The Generic Letter and the requirements for each of its supplements were addressed in the Prairie Island IPE submittal to the NRC on March 1, 1994.

Supplement 4 to Generic Letter 88-20, Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities, was issued in June of 1991. The IPEEE is to specifically address seismic and internal fire events, and then other remaining risk concerns from external initiators (e.g., high winds, floods). Supplement 5 modified the scope of the seismic portion of the IPEEE to be equivalent to a reduced scope seismic margins assessment with a focus on a few key critical components.

The primary objectives of the IPEEE, as stated by the NRC in the Generic Letter, are for each utility to develop an appreciation of severe accident behavior; understand the most likely severe accident sequences that could occur at its plant under full-power operating conditions; gain a qualitative understanding of the overall likelihood of core damage and radioactive releases by modifying hardware and procedures that would help prevent or mitigate severe accidents.

The specific objectives are to:

- Identify the potential accident sequences that contribute to the overall core damage frequency.

- Identify cost effective modifications to the plant design, operating procedures, training or maintenance procedures that would reduce the likelihood of any accident outliers that are identified.

- Maximize participation in the evaluation process by NSP personnel.

- Provide a well organized and clearly written summary of the Prairie Island IPEEE to facilitate communication of the results to both NRC and NSP, as well as to serve as a tool for communicating the results to interested members of the public.

- Develop the risk-based tools and methods, and the associated documentation, to support resolution of future regulatory, safety, or operational issues for Prairie Island.

1.2 Conformance with Generic Letter and Supporting Materials

NSP's Probabilistic Risk Assessment (PRA) Group has been actively involved with the IPEEE process since its inception. Lead responsibility for the IPEEE effort was assigned to the PRA Group, which is a part of NSP's Licensing and Management Issues department. The PRA Group directed all aspects of the analysis, with general consulting services provided by TENERA, Inc., and EQE International. The PRA Group directed the effort, coordinated the work with affected members of the plant staff, was involved in various aspects of the analysis process, and has actively worked with the consultants to ensure the transfer of technology to NSP, so that future applications of the IPEEE can be performed by NSP personnel with the need for only limited external resources. Further details of the organization are provided in Section 3 of this report.

This report documents NSP's completion of the IPEEE in accordance with Supplement 4 and 5 to Generic Letter 88-20. A comprehensive review of the IPEEE work was performed by NSP personnel. A review team composed of plant staff and corporate personnel of various disciplines reviewed this report prior to its publication as described in Section 2.

In addition to the reviews of the completed analyses, various reviews and validations were performed as part of the analytical process. Walkdowns supporting each of the topics reviewed in the IPEEE were performed to confirm input assumptions and final conclusions. References to these walkdowns are provided in each appendix.

For the seismic IPEEE, a modified focused scope seismic margins assessment was performed. Screening of the capacity of systems, structures and components (SSCs) was evaluated at 0.3g in accordance with EPRI NP-6041-SL (A Methodology for Assessment of Nuclear Power Plant Seismic Margin). The critical safety functions necessary to respond to the postulated conditions following a seismic event were reviewed to identify the key systems used to accomplish those functions. Through work performed as part of the SQUG program, it was demonstrated that there is high confidence that

multiple systems would be available to accomplish core cooling and containment pressure control for seismic events as large as the SSE. The results of this modified focused scope seismic margins assessment are provided in Appendix A.

The fire IPEEE analysis was completed by performing a fire PRA supported by the deterministic evaluation techniques of EPRI's Fire Induced Vulnerability Evaluation Methodology (FIVE). The analysis concluded that the overall core damage frequency is low (on the order of 6E-5/yr) which is comparable to the internal events PRA results. Sensitivity analyses were performed for the internal fire analysis to identify important fire areas, operator actions, and plant components that drive the potential risk associated with internal fires. The results of the fire PRA are presented in the discussion of accident sequence results in Appendix B.

The majority of the assessment of other external events (Appendix C) did not require detailed evaluation or sensitivity analyses, as most issues could be resolved by comparison with the NRC's Standard Review Plan. When additional probabilistic or deterministic analyses were needed for these other external events, bounding analyses or sensitivity studies were performed to address specific uncertainties.

1.3 Structure of IPEEE Report

NUREG 1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities", identifies reporting guidelines for IPEEE submittals. A cross-reference between the headings in the standard table of contents suggested in NUREG-1407 and this report is provided in Table 1. The most notable difference between the suggested format and that used in this report is that the individual evaluations for severe accident vulnerabilities for seismic events, internal fires, and other external events are contained in separate appendices at the end of this report. The seismic margins assessment is in Appendix A; the assessment of internal fires is in Appendix B; and the evaluation of other external events is in Appendix C. Each appendix is designed to stand alone in order to facilitate their separate review.

Table 1

Cross-Reference Between NUREG-1407 Topics and Contents of this Report

NUREG 1407, Table C.1 Topic	Location in this Report
Executive Summary: - Background and Objectives - Plant Familiarization - Overall Methodology - Summary of Major Findings	 Main report and section 1.1 of each appendix Section 1.2 of each appendix Main report and section 1.3 of each appendix Main report and section 1.4 of each appendix
Examination Description: - Introduction - Conformance with Generic Letter and supporting material - General Methodology - Information Assembly	 Section 1.1 of main report Section 1.2 of main report Section 2 of each appendix Section 2 of each appendix
Seismic Analysis (seismic margins assessment)	Appendix A
Internal Fires Analysis	Appendix B
High Winds, Floods and Others	Appendix C
Licensee Participation and Internal Review Team	Section 2.0 of main report
Plant Improvements and Unique Safety Features	Appendix A, Section 2 Appendix B, Section 2 Appendix C, Sections 2.2 - 2.4
Summary and Conclusions	Section 3 of main report (Overall) and Appendix A, Section 2.6 Appendix B, Section 2 Appendix C, Section 3.0

2. UTILITY PARTICIPATION AND INTERNAL REVIEW TEAM

2.1 IPEEE Program Organization

The Director of NSP's Licensing and Management Issues department has the overall review and approval responsibility. The members of NSP's PRA group report to the Director of Licensing and Management Issues and, as a team, act as the NSP PRA/IPEEE Program Manager. The PRA group is responsible for the details and overall project management for all PRA and IPEEE analyses at NSP. Three PRA group members worked on the Prairie Island PRA/IPEEE, all of whom are located at the plant site. The experience and training of these team members includes the following:

- One formerly SRO-licensed engineer, currently Nuclear "certified" per the NSP nuclear certification training program; another nuclear certified engineer; and one associate engineer with a plant operations background.
- All three PRA Group members were primary contributors to the PINGP IPE analysis.
- Involvement of the group members in utility initiatives includes membership in the Westinghouse Owner's Group Risk-Based Technologies Working Group, the EPRI Risk and Reliability Workstation User's Group, and the EPRI Safety and Reliability Assessment Target Steering Committee.
- Collectively, these team members have over 35 years of nuclear power plant experience.

TENERA, Inc. and EQE International, provided consulting services in support of the IPEEE program. TENERA has worked with the NSP PRA group since the inception of NSP's IPE program. EQE International provided expertise in the seismic/structural engineering area, having extensive industry experience in seismic PRAs, seismic margin assessments, and USI A-46 programs. TENERA and EQE International actively worked with the NSP PRA group at PINGP to ensure the transfer of IPEEE technology was accomplished.

2.2 Composition of the Internal Review Team

In addition to the involvement by NSP's PRA group in the IPEEE program, various plant organizations were involved throughout the evaluations as well as during an internal review process of the IPEEE results. For the IPEEE, a review team was selected that would provide a thorough and diverse consideration of both the assumptions input to the analyses, and the results and conclusions produced by those analyses. This review took advantage of specific organizations that have related programs underway to review the IPEEE results. Examples include the Prairie Island SQUG (Seismic Qualification User's Group) effort (associated with Unresolved Safety Issue A-46) and the Fire Protection group (associated with maintaining the Appendix R analyses).

3. IPEEE INSIGHTS FOR PRAIRIE ISLAND AND RECOMMENDATIONS

3.1 Conclusions and Insights from the IPEEE Analyses

The external events examination was conducted in three distinct phases: seismic, internal fires, and other external events. Each of these individual studies is described in the appendices of this report. The following summarizes the conclusions of these assessments, including the specific insights and recommendations for plant improvements.

3.1.1 Seismic Analysis

NSP originally planned to respond to Generic Letter 88-20, Supplement 4, by performing a seismic probabilistic risk assessment (PRA) for Prairie Island. By letter dated September 25, 1995, Prairie Island notified the staff of a change in the manner in which the seismic IPEEE would be completed. This change is based on new information regarding large reductions in the seismic hazard estimates for sites in the eastern United States, as presented in draft NUREG-1488, "Revised Livermore Seismic Hazard Estimates for 69 Nuclear Power Plant Sites East of the Rocky Mountains," issued April of 1994. This new information was incorporated within Supplement 5 of Generic Letter 88-20, which provides the basis for NSP's decision to change the approach of completing the seismic IPEEE from a seismic PRA to a seismic margins assessment.

A portion of the effort for the PRA was accomplished (i.e., walkdowns and initial screening) when the NRC issued Supplement 5 to the Generic Letter. NSP elected to change its approach in accordance with Supplement 5 and has completed the analysis of seismic events in the form of a reduced scope seismic margins assessment with the focus on a few known weaker, but critical, components. The majority of the components included in the assessment were determined to meet the screening criteria established in EPRI NP-6041-SL. This result in itself indicates that most of the components have a relatively high seismic capacity. The remaining components; i.e., those not meeting the screening criteria, were evaluated further and 1) were determined either to be adequate for the safe shutdown earthquake (SSE); 2) were determined to be unnecessary due to the particular seismic failure mode and/or available plant equipment redundancy; or 3) are to be addressed under the closure of the Prairie Island SQUG program. Overall, it was concluded that there is no significant plant vulnerability to severe accidents attributable to seismic events at Prairie Island.

It should be noted that the seismic analysis conducted as part of the IPEEE program was done in conjunction with the efforts at Prairie Island to address seismic issues associated with the USI A-46 program. This coordination of programs is the basis for crediting certain components that will be upgraded to the SSE level under the closure of the SQUG program. Further, it was shown that many unscreened components that were not dispositioned in the USIA-46 program would not be expected to lead to the inability to cool the core if they were assumed to fail following a seismic event. In each case, additional random failures of equipment are necessary before inadequate core cooling would be expected.

Other significant conclusions of the seismic margins assessment include:

- The seismic walkdowns performed as part of the IPEEE found most of the components and structures reviewed to be seismically adequate (i.e., suitably anchored and/or seismically rugged). Those items that could be considered potentially vulnerable were subjected to the more rigorous seismic evaluation referred to above;

- Concrete block walls were either screened from further consideration because their failure would cause no adverse consequences, or they were further evaluated and found to have sufficient seismic capacity;

- The review of relays credited in the IPE revealed that there were relays beyond those considered in the SQUG program scope that had to be evaluated. However, it was determined that none of these relays are considered "bad actors";

- Few flat bottom tanks fell solely under the scope of the seismic IPEEE (i.e., SQUG has identified some tanks as outliers that will be addressed under the closure of that program). Those that did were either screened or shown to have limited consequences should they fail;

- A review of containment response reveals no conditions that are unique to seismic events or that have not already been evaluated as part of the internal events PRA (IPE).

- A recommendation from the seismic margins assessment is to restrain or remove wall hung ladders and scaffolding that are located near safety related equipment to reduce the impact of seismically induced relay chatter.

3.1.2 Internal Fires Analysis

The core damage frequency resulting from fires is estimated to be less than 7E-5/yr. This total is on the same order of magnitude as the core damage frequency of the internal events PRA. It should be noted that these results include a number of conservative assumptions. For example, automatic or manual fire suppression were not credited except in the control room, cable spreading room, and the AFW pump rooms. Fires were also assumed to completely engulf an area once ignited.

More than 75 percent of the plant risk associated with the internal fires can be traced to five fire areas/burn areas. These rooms/burn areas are the Auxiliary Building Ground Floor Unit 1 (Fire Area 58), the cable spreading or relay room (FA 18), the main control room (FA 13), the Turbine Building Ground & Mezz Floor Unit 1 (FA 05, 08, 14, 21, 27, 57, 69, 94), the 480V Safeguards Switchgear Room–Bus 121 (FA 22), and Access Control (FA 15). Of these, the largest contributor to core damage frequency is the Auxiliary Ground Floor Area, containing both trains of Safety Injection, RHR,

Component Cooling and all three charging pumps. This fire area is important due to the equipment located in this area that provides cooling to the Reactor Coolant Pump (RCP) seals. For this area, Auxiliary Feedwater remains available to provide secondary heat removal. Protection of the cables for a train of component cooling as well as the ability to crosstie Unit 2 component cooling provides adequate protection from a RCP seal LOCA.

Operator actions that dominate the fire PRA are associated with starting the standby component cooling water train, crosstieing the Unit 2 component cooling water system, and activating the hot shutdown panel. The purpose of the first two actions is prevention of a seal LOCA should all charging and component cooling water be lost during a fire. Activating the hot shutdown panel is important for the relay room and control room fires.

The principal finding of this analysis is that there is no credible single fire in the plant that would lead directly to the inability to cool the core. Without additional random equipment failures unrelated to damage caused by the fire, core damage will not occur. As a result, this study concludes that there are no major vulnerabilities due to fire events at the Prairie Island Nuclear Generating Plant.

3.1.3 High Winds, Floods, and Others

The assessment of other external events shows that there are no other credible external events that are of a safety concern to the Prairie Island plant site. No vulnerabilities were identified, and the screening criteria contained in NUREG-1407 and Generic Letter 88-20 (Supplement 4) were satisfied for all events. A simple walkdown was performed to confirm these results.

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Appendix A
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Seismic Analysis

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A.1. INTRODUCTION

A.1.1 Background

This report documents Northern States Power Company's (NSP's) response to Supplement 4 of Generic Letter 88-20, "Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," for the Prairie Island Nuclear Generating Plant. The assessment described in this appendix addresses seismic events. The analysis and its results, which are described in the following sections, provide insights with respect to the response of the Prairie Island plant to a seismic event. As described in Supplement 5 to Generic Letter 88-20, an evaluation equivalent to a reduced scope seismic margins assessment was performed for Prairie Island with an additional focus on a few key critical components.

A.1.2 Plant Familiarization

The Prairie Island Nuclear Generating Plant is a two unit facility, each unit consisting of a 2-loop pressurized water reactor within large dry containments. Westinghouse Electric Corporation designed and supplied the nuclear steam supply system and the turbine-generator units. Pioneer Service and Engineering (now Fluor Power Services, Inc.) was the plant's architect-engineer. Northern States Power Company constructed the plant. Each reactor core produces 1650 MWt with an electrical output of 560 MWe, using 121 fuel assemblies. The plant is located within the city limits of Red Wing, Minnesota. Construction started on June 26, 1968. Full commercial operation began on December 16, 1973 for Unit 1 and December 21, 1974 for Unit 2.

The original design considered seismic events in the design of Class I systems, structures and components. Chapter 12.2.1 of the Prairie Island USAR defines Class I as "structures and components including instruments and controls whose failure might cause or increase the severity of a loss-of-coolant accident or result in an uncontrolled release of substantial amounts of radioactivity, and those structures and components vital to safe shutdown and isolation of the reactor." Class I structures and equipment are designed for a horizontal ground acceleration of 0.06g for the Operating Basis Earthquake (OBE) and 0.12g for the Safe Shutdown Earthquake (SSE).

Seismic evaluations of masonry walls were performed in the early 1980s under I&E Bulletin 80-11 activities. These evaluations resulted in modifications that increased the seismic capacity of certain masonry walls.

A.1.3 Overall Methodology

NSP originally planned to respond to Generic Letter 88-20, Supplement 4 [1], by performing a seismic probabilistic risk assessment (PRA) for Prairie Island. The walkdowns and screening evaluations of essential structures and equipment were performed following procedures applicable to a focused scope plant, which was how Prairie Island was categorized in NUREG-1407. In accordance with Supplement 5 to Generic Letter 88-20 [2], NSP subsequently elected

to complete the Prairie Island seismic IPEEE by conducting the equivalent of a reduced scope seismic margins assessment with an additional focus on a few critical key components identified in Attachment 1 to Supplement 5.

The overall methodology for the Prairie Island seismic IPEEE thus consists of the following steps:

1. Systems and components considered in the seismic IPEEE were identified based on insights from the internal events PRA.

2. A walkdown of key plant structures, systems, and components was performed following the EPRI NP-6041-SL [3] procedures for a focused scope seismic margin evaluation to screen seismically rugged structures and components from further review.

3. A list was compiled of components that did not meet the screening criteria in the preceding step. This compilation of unscreened components represents a conservative set of outliers for a reduced scope seismic margin assessment.

4. Following the guidance of NUREG-1407 [14], components were evaluated using the criteria of the Generic Implementation Procedure (GIP) [22] using the ground and in-structure SSE response spectra.

5. Structures and components outside the SQUG program scope that were not screened by the GIP criteria were subsequently evaluated to the SSE level using the requirements of the USAR.

6. For any outliers that remained, a systems analysis was performed by reviewing the effect of component failure on plant systems needed to respond to a seismic event in bringing the plant to a safe shutdown condition.

These steps are described in more detail in Section A.2.

A.1.4 Summary of Major Findings

The Prairie Island seismic margins assessment concludes that all important safety functions can be accomplished following a seismic event. The safety functions considered for the IPEEE are similar to those used to define the accident sequence types quantified in the IPE:

- Reactivity Control
- Reactor Coolant Pump (RCP) Seal Cooling
- Secondary Heat Removal
- Short Term Inventory Control (Injection)
- Long Term Inventory Control (Recirculation)
- Containment Pressure Control
- Important Support Systems

Most components included in the seismic margin assessment for Prairie Island that support these functions have relatively high seismic capacities. Components that do not meet the reduced scope seismic margins assessment screening criteria and contribute to the safety functions noted above are summarized in Table A.1. These results apply equally to both units 1 and 2 as compete walkdowns and seismic margins assessments were performed for both units.

Some components identified in Table A.1 are to be addressed under the SQUG program. These include outliers that will be seismically upgraded or otherwise shown to be seismically adequate to the SSE.

Table A.1 Prairie Island Seismic IPEEE: Summary of Major Findings

Function/Components	Seismic Failure Mode	Postulated Effect of Failure	Conclusions
Reactivity Control	N/A	N/A	All Components Screened
RCP Seal Cooling • 13, 23 charging pumps • Component Cooling Water valves MV-32117 & 32267 • PS-16262 thru 16265	• Anchorage • Interaction • Mercoid Switch	• Loss of seal cooling supply • Unable to change position • Loss of CC auto-start signal	• Unnecessary due to redundancy from charging pumps 11, 12, 21 and 22 • Valves already in correct position; position does not need to change • CC pump auto-start signal is redundant to ESF signal; manual start is also available
Secondary Heat Removal • SG level logic relays/bistables • AFW Trip/Throttle Valves CV-31059 and 31060 • Condensate storage tanks	• Anchorage • Seismic-induced trip • Not seismically designed	• Loss of AFW auto-start signal • Loss of 1 train of AFW per unit • Loss of SG makeup	• Turbine driven AFW start signal occurs on LOOP • Operator action can recover valve • Not credited; operators can align cooling water to suction of AFW pumps from the control room
Short Term Inventory Control (Injection) • SI Cold Leg Inj. MV-32068	• • Interaction	• • Unable to change position	• • Valve in correct position; no change needed
RCS Cooldown and Depressurization • Pressurizer Relief Valves 1RC-10-1&2, 2RC-10-1&2 • Boric Acid Filters & Transfer Pumps • CV-31421 • Emergency Boration Supply MV-32086 • SG PORV Accumulators	• Seismic capacity • Anchorage • Interaction • Interaction • Anchorage	• Loss of primary depressurization • Loss of additional source of boric acid • Loss of train of auxiliary spray • Valve unable to open • Loss of decay heat removal method	• Function not credited • Function not credited • Function not credited • Function not credited, valve does not need to open • Function not credited
Long-Term Inventory Control (Recirculation)	N/A	N/A	• All components screened
Containment Pressure Control • 13 Fan Coil Unit • Containment Spray Pumps • Transmitters 1PT-948 and 2PT-945	• Seismic capacity • Anchorage • Interaction	• Reduced capacity for containment cooling • Loss of one means of containment pressure control • Reduced redundancy in P signal source	• To be addressed by SQUG • Not credited due to capacity of FCUs • Unnecessary due to not crediting containment spray

Table A.1, continued: Prairie Island Seismic IPEEE: Summary of Major Findings

Function/Components	Seismic Failure Mode	Postulated Effect of Failure	Conclusions
Support Systems: Cooling Water			
• FCU Cooling Water Supply, CV-39401 & 39409	• Interaction	• Loss of cooling to FCUs	• To be addressed by SQUG
• FCU Cooling Water Return, CV-39411	• Interaction	• Damage to limit switch; unable to change position	• Valve in correct position and does not need to change positions
• 11 & 21 Screenhouse Roof Exhaust Fans	• Anchorage	• Potential impact to Cooling Water diesel pump	• To be addressed by SQUG
• 12 & 22 Diesel Cooling Water Pumps	• Anchorage and shaft instability	• Loss of cooling water	• To be addressed by SQUG
• Air Compressors for 12 & 22 Cooling Water Pumps	• Anchorage	• Loss of charging to air receivers	• Charging function not credited; air receivers sufficient to start diesels
• 121 Cooling Water Pump	• Anchorage and shaft instability	• Reduced redundancy in Cooling Water pumps	• Not credited due to capacity of diesel CL pumps
• FCU Cooling Water Supply MV-32386	• Interaction	• Unable to change position	• Valve is already in correct position; interaction won't cause valve to change positions
• Cooling Water Pump Discharge Header Pressure Switches (PS-16002, 16009, 16259)	• Mercoid switches	• Loss of Cooling Water pump auto-start signal	• Redundancy in start signal sufficient; manual start capability also exists
Fuel Oil			
• 121/122 CL Pump FO Storage Tanks	• Undetermined flexibility of buried pipe	• Fuel loss leads to loss of Cooling Water	• To be addressed by SQUG
• 121/123 DG FO Storage Tanks	• Undetermined flexibility of buried pipe	Fuel loss leads to loss of Emergency AC sourceFuel loss leads to loss of Emergency AC source	• To be addressed by SQUG
• 122/124 DG FO Storage Tanks	• Undetermined flexibility of buried pipe		• Unnecessary due to capacity available in Tanks 121 and 123 (Assumed 121 and 123 have been dispositioned by SQUG)
Room Cooling			
• Relay Room North (121/122) & South (121/122) Unit Coolers	• Anchorage	• Exceed critical ambient temperature of equipment	• To be addressed by SQUG
• 121/122 Control Room Chillers	• Unrestrained vibration isolators	• Exceed critical ambient temperature of equipment	• To be addressed by SQUG
• 11, 12, 21, 22 RHR Unit Coolers	• Structural integrity	• Exceed critical temperature of RHR pump motor	• Room cooling function determined to be unnecessary
• Switchgear/Bus Room Cooling	• Anchorage	• Exceed critical temperature of bus room equipment	• Room cooling function determined to be unnecessary.
• D5/D6 Bus Room Aux Air Handlers & Aux Condensing Units	• Anchorage	• Exceed critical temperature of bus room equipment	• Room cooling function determined to be unnecessary
DC Power			
• 11, 12, 21, 22 Batteries	• Inadequate supports	• Loss of DC supplies	• To be addressed by SQUG
• 11, 12, 22 Battery Chargers	• Anchorage	• Loss of battery support	• To be addressed by SQUG
• Panels 11, 12 & 22	• Anchorage	• Loss of DC distribution	• To be addressed by SQUG
• Panel 153	• Interaction and anchorage	• Loss of DC distribution	• Does not support credited equipment

Function/Components	Seismic Failure Mode	Postulated Effect of Failure	Conclusions
AC Power			
• D1/D2 Gage Panels	• Unrestrained vibration isolators	• Potential loss of DG engines	• To be addressed by SQUG
• 12/22 DG Jacket HX	• Inadequate connection	• Loss of engine cooling	• To be addressed by SQUG
• 480V MCCs 1AB1, 1AB2, 1K1, 1L2, 2K2, 1TA1, 1TA2, 2LA2	• Interaction and anchorage	• Loss of trains of various credited systems (e.g., SI, charging, FCUs)	• To be addressed by SQUG
• Panels 132 & 133	• Interaction	• Loss of 4kV and 480V bus room cooling	• Room cooling function determined to be unnecessary
• Buses 11, 12, 13 & 14	• Anchorage	• No adverse effect	• Do not support credited equipment
• 480V MCCs 1M1, 1M2, 1MA1, 1MA2	• Anchorage	• No adverse effect	• Do not support credited equipment
• 14 and 24 Inverters	• Anchorage	• No adverse effect	• Do not support credited equipment
• Panels 117 and 217	• Anchorage	• No adverse effect	• Do not support credited equipment
• Panels 313 and 3133	• Interaction	• No adverse effect	• Do not support credited equipment
• Bus 22 Undervoltage Relays 2-27A/B22-XA and 2-27B/B22-XA	• Interaction and anchorage	• No adverse effect	• Do not support credited equipment
• D2 DG Control Panel	• Interaction with wall-mounted scaffolding	• Loss of 1 train of emergency AC power	• Outlier, to be addressed by maintenance
• Bus 25	• Interaction with wall-hung ladder	• Loss of 1 train of emergency AC power	• Outlier, to be addressed by maintenance
Miscellaneous			
• Control Room Ceiling	• Diffuser panels falling	• Potential damage to panels and threat to operators	• To be addressed under SQUG

A.2. SEISMIC ANALYSIS

A seismic margins assessment of the Prairie Island Nuclear Generating Plant was conducted between 1994 and 1996 to address the requirements of Generic Letter No. 88-20, Supplement 4, "Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," dated June 1991. In accordance with Supplement 5 to Generic Letter 88-20, the assessment is equivalent to a reduced scope seismic margins assessment with an additional focus on a few key components. These components include relays, block walls, flat-bottom tanks, and other components identified during the plant walkdowns.

The Prairie Island seismic margins assessment follows the guidance of EPRI NP-6041-SL with additional input from the internal events probabilistic risk assessment (PRA). This assessment included the following elements:

- System, structure and component success path selection
- Plant walkdowns
- Component screening
- Seismic margin assessment

The success paths for the Prairie Island seismic IPEEE were derived from the logic models developed for the internal events PRA. Active components of all systems that could be available following a loss of offsite power were included on the equipment list used during the walkdown and screening activities. With this approach, multiple potential success paths were identified for each safety function. The list was further supplemented with some passive components that were not modeled in the internal events PRA, such as tanks, heat exchangers, panels, cabinets, and support structures.

The plant walkdowns were conducted following the guidelines for a seismic margin assessment presented in EPRI NP-6041-SL. The walkdown was performed to screen seismically rugged structures and components from further review, to identify the potential failure modes and system interactions for components that could not be screened from further review during the walkdown, and to obtain data for use in subsequent evaluations. The walkdown teams included systems analysts and seismic capability engineers. The walkdown screening was based on a seismic margin earthquake having a peak 5% damped spectral acceleration of 0.8g or less. This screening level is applicable to a focused scope plant and is conservative for a reduced scope plant. The results of the walkdowns were recorded on data sheets for future reference. Seismic issues requiring further review were identified.

Evaluations were performed to further screen components from more detailed review. The component screening evaluations were performed following NUREG-1407 guidance for seismic margin assessment of reduced scope plants. Seismic input was based on the ground and in-structure SSE response spectra. Equipment and vessels were screened using the criteria of the GIP.

Structures and components outside the scope of the SQUG program for which the GIP criteria were not applicable (e.g., civil structures, masonry walls, and NSSS components) were screened to the SSE following the requirements of the USAR.

Based on the walkdown and the screening evaluations, nearly all of the essential components were screened from further review. Many components were found acceptable to the SSE level by the Prairie Island SQUG program or will be seismically upgraded for the SSE by the SQUG program as part of the actions to resolve the identified outliers.

For those components that were not eliminated from further review during the walkdown and screening evaluations, systems analyses were used as an additional screen. These systems analyses considered the effect of failure of the components as well as determining whether other systems would be available to provide the critical safety functions needed during an accident following a seismic event.

The remaining unscreened components are outliers, which include components with potential seismic interactions from wall-hung ladders and scaffolding. These outliers can be addressed by restraining or relocating the ladders through a maintenance activity.

A.2.1 Plant Systems

The plant systems considered in the seismic IPEEE are a subset of those considered in the IPE. An earthquake could reasonably produce a loss of offsite power (LOOP) and/or a small-break loss of coolant accident (SLOCA) initiating event. The seismic portion of the IPEEE focused on the frontline and support systems that would be called upon to prevent core damage for these two initiating events. Support systems that may not be seismically rugged, such as Instrument Air, were not credited (i.e., they were assumed to have failed as a result of the earthquake). The systems considered are listed below by the functions they support.

- Reactivity Control
  - Reactor Protection System
- Reactor Coolant Pump Seal Cooling
  - Chemical & Volume Control (Charging Pumps)
  - Component Cooling Water
- Secondary Heat Removal
  - Auxiliary Feedwater System
- Short Term Inventory Control (Injection)
  - Safety Injection (High Head Injection Mode)
  - Residual Heat Removal (Low Head Injection Mode)
- Long Term Inventory Control (Recirculation)
  - Safety Injection (High Head Recirculation Mode)
  - Residual Heat Removal (Shutdown Cooling Mode)
  - Residual Heat Removal (Low Head Recirculation Mode)
- Containment Pressure Control
  - Containment Air Cooling System (FCUs)

    - Containment Spray
- Important Support Systems
    - Emergency Diesels and auxiliaries / 4kV
    - 480 VAC
    - 120 VAC
    - 125 VDC
    - Cooling Water

This section discusses the plant systems considered in the seismic IPEEE and the specific equipment comprising those systems.

A.2.1.1 Plant Frontline Systems Included in the IPEEE

A discussion of the frontline plant systems included in the seismic IPEEE by functional area is included in this section. A brief discussion of those systems considered in the IPE but not credited in the IPEEE is also provided.

A.2.1.1.1 Reactivity Control

Reactor Protection System (RPS)

Instrumentation associated with the Reactor Protection System (RPS) monitors key plant parameters to determine whether the plant processes are within bounds of important operating parameters associated with normal operation. A seismic event sufficiently large to cause equipment damage is expected to result in an RPS trip signal from a variety of causes. Further, the conditions postulated to exist in the plant as a result of a seismic event include a loss of off-site power or a small loss of coolant accident, either of which would cause a reactor trip. In response to these postulated conditions, rods are expected to be inserted quickly.

ATWS Mitigation System Actuation Circuitry (AMSAC)

AMSAC is a means of control rod insertion triggered by separate and diverse logic from the RPS. The potential for a failure to trip coincident with an earthquake is considered to be of low potential and AMSAC is not considered to be necessary in the seismic IPEEE.

A.2.1.1.2 RCP Seal Cooling

Chemical & Volume Control System (CVCS)

The IPE considered two functions of CVCS: RCP seal injection, and Auxiliary Spray for the pressurizer. The system consists of three variable speed positive displacement pumps that take suction from the Volume Control Tank (VCT) or the Refueling Water Storage Tank (RWST) as a backup. In the IPEEE, no credit is taken for the system capacity for RCS make-up. Similarly, no credit is taken for the Auxiliary Spray function. The RCP seal cooling function requires one pump to be taking suction from either the VCT or RWST and supplying flow through a seal injection filter to the RCP seals. A return path is also necessary through either the seal return heat exchanger to the VCT or through the seal return relief valve.

Component Cooling (CC) Water System

The Component Cooling Water System provides an intermediate cooling system between the heat exchangers in potentially radioactive systems and the Cooling Water System. CC is a safeguards system consisting of two parallel loops each of which is composed of a pump, heat exchanger, and associated piping and instrumentation. The two loops are capable of being cross-connected at the suction and discharge of the pumps. Either loop also has the capability of being cross-connected with either loop in the opposite unit. The system provides cooling water to important components including the RHR heat exchangers, heat exchangers for the Containment Spray, Safety Injection and RHR pumps, and the RCP thermal barrier.

A.2.1.1.3 Secondary Heat Removal

Auxiliary Feedwater System (AFW)

The function of the Auxiliary Feedwater System is to supply steam generator makeup for normal transients such as heatup and cooldown when the water demands are low or main feedwater is not available. The system also provides high pressure make-up to the steam generators under emergency conditions to assure a reactor coolant system heat sink is always available. The AFW system consists of two independent full capacity parallel trains. One train is equipped with a motor-driven pump while the other train is equipped with a steam turbine-driven pump. If needed, the motor-driven AFW pump from the opposite unit can be aligned for makeup. The steam supply for the turbine-driven pump can be supplied from either steam generator.

The plant's design allows both pumps to take suction from either the condensate storage tanks or the cooling water system. For the seismic IPEEE, no credit is taken for the condensate storage tanks since they are not seismically designed. The pumps can be aligned to take suction from the cooling water system which is fed from the Mississippi River. The success criteria for adequate AFW flow is one of the pump trains for each unit supplying design capacity flow to either one of the two steam generators.

Main Feedwater System

Normally, the Main Feedwater System provides the cooling water flow to the steam generators to remove the heat from the Reactor Coolant System. Main Feedwater is not available following a seismic event because of the postulated loss of off-site power. Therefore, no credit is taken for this system in the seismic IPEEE.

A.2.1.1.4 Short Term Inventory Control (Injection Mode)

Safety Injection (High Head Injection)

The primary function of the Safety Injection (SI) system is to remove stored energy and decay heat from the reactor core following a loss of primary or secondary coolant. The system has two operating modes: High Head Injection mode in which water from stored sources is injected into the RCS, and High Head Recirculation mode in which water from the containment sump (collected from the loss of coolant breach) is returned to the RCS. For Short Term Inventory Control, SI responds in the Injection mode, which is described below.

The SI system consists of two independent trains. Each train consists of a pump with associated suction and discharge valves. The pumps are motor-driven centrifugal pumps with a capacity of approximately 700 gpm at 1300 psig, and a shutoff head of approximately 2170 psig. The trains initially take suction from one of from the highly concentrated boric acid storage tanks (BAST), then automatically switch to the Refueling Water Storage Tank (RWST) when the BAST reaches its low level setpoint. The SI Injection mode ends when the RWST reaches its low level setpoint (33%). At this point, the suction of one train of the SI pumps can be manually transferred to the containment sump B via the RHR pump discharge. This marks the beginning of the Long Term Inventory Control phase and the High Head Recirculation mode of SI.

Pressurizer Power Operated Relief Valves (PORV)s

There are two pressurizer PORV trains per unit. These valves, when open, allow flow from the top of the Pressurizer to the Pressurizer Pressure Relief Tank. Each train consists of a motor operated block valve and an air operated relief valve. Each PORV is an air operated, fail-closed, valve. The incoming air supply line to each PORV is equipped with an air accumulator and a check valve to allow approximately 15 valve openings should instrument air be lost. Since instrument air is assumed to be unavailable, pressurizer PORVs and bleed and feed operations are not credited in the seismic IPEEE.

Residual Heat Removal (Low Head Injection)

The Residual Heat Removal (RHR) system has a similar purpose to that of the SI system, except that RHR operates when the RCS has significantly depressurized. The system has three modes of operation: Low Head Injection in which water from stored sources is injected into the RCS, Low Head Recirculation in which water from the containment sump (collected from the loss of coolant breach) is returned to the RCS, and Shutdown Cooling in which RCS decay heat is rejected through the RHR heat exchangers. For the seismic IPEEE, in which it is postulated that the earthquake has caused a loss of off-site power or a small loss of coolant accident, the injection mode is not considered since the RCS can not be depressurized easily without instrument air which is assumed to be unavailable following a seismic event. Instead, RHR supports the Long Term Inventory Control function through the Low Head Recirculation and Shutdown Cooling modes, which are described in the following section.

A.2.1.1.5 Long Term Inventory Control (Recirculation)

Safety Injection (High Head Recirculation)

The SI system, and its High Head Injection mode of operation, was described in the previous section. In the Long Term Inventory Control function, the SI system transitions to its High Head Recirculation mode of operation. In this mode, the SI pump suction source is transferred from the RWST (now depleted) to the discharge line of the RHR pumps which are drawing on the collected RCS coolant (spilled from the small loss of coolant break location) in containment sump B. The water that collects in containment sump B is drawn by the RHR pumps and cooled through the associated RHR heat exchanger before the SI pumps inject it back into the RCS.

Residual Heat Removal (Low Head Recirculation, Shutdown Cooling)

As described above, the RHR system has two modes of operation that could be called upon in responding to the seismic event: Low Head Recirculation and Shutdown Cooling. To support these modes of operation, the RCS must be depressurized to effect transition from SI to RHR. The RHR system is also used to provide suction for the SI and Containment Spray systems when they are in the recirculation mode of operation.

The RHR system is divided into two trains. Each train contains one pump and one heat exchanger. Each pump has a rated capacity of approximately 2000 gpm at 120 psig, and a shutoff head of approximately 140 psig. Each train of RHR has a dedicated injection path to the reactor vessel. In recirculation mode, RHR pump suction is aligned to containment sump B which is a collection point for water spilled from the postulated small loss of coolant accident break location. Sump fluid is pumped through the RHR Heat Exchangers (cooled by the Component Cooling Water System) and then directed into the reactor vessel through the injection nozzles. Under the conditions postulated for the seismic IPEEE, the RHR Low Head Recirculation mode may not be available. Decay heat removal would be accomplished through SI (injection and recirculation) and then RHR in the Shutdown Cooling mode which is described below.

The Shutdown Cooling mode of the RHR system is used to provide decay heat removal for small LOCA events and steam generator tube ruptures. After the RCS has depressurized below pump shutoff head pressure, the RHR pumps take suction on the RCS hot legs and discharge through the associated heat exchangers back into the RCS at the loop B cold leg. The success criteria for the Shutdown Cooling mode of RHR is for one train to take suction from the RCS hot legs, transfer heat to the Component Cooling Water system through the associated heat exchanger and return the fluid to the RCS through the loop B cold leg. The availability of safety injection in recirculating mode is a backup should depressurization not occur. In this event, the SDC mode of RHR is unnecessary.

A.2.1.1.6 Containment Pressure Control

Containment Air Cooling System

Adequate heat removal capability for the containment is provided by two separate, full capacity, engineered safeguards systems: Containment Air Cooling and Containment Spray. These systems involve different engineering principles and serve as independent backup for one another. Containment Air Cooling consists primarily of four Fan Coil Units (FCUs) within the containment vessel designed into two independent trains. Each train consists of two condensing units, two circulating fans and associated ductwork and dampers. All FCUs are operating under normal conditions, receiving cooling water flow from the non-safety chilled water system. Under emergency conditions, the cooling medium switches to the safety related cooling water system (CL). To successfully respond to the conditions postulated following a seismic event, the Containment Air Cooling system must have two of four FCUs available (taking no credit for Containment Spray).

Containment Spray

The Containment Spray system cools the containment environment under LOCA or steamline break accident conditions by spraying through spray nozzles located at the containment dome. The system is automatically initiated by a "P" signal which is generated either manually or by containment pressure reaching 23 psig. The system consists of two independent parallel trains. Each train consists of a motor-driven pump, associated piping and valves, and a spray ring header attached to the containment dome. Each train takes suction from both the borated refueling water storage tank (RWST) and a caustic addition standpipe. Each pump is capable of discharging caustic borated flow of approximately 1300 gpm at 220 psig to an independent spray header. The success criteria for the system is one train fully operational (taking no credit for the containment FCUs). Containment Spray need not be credited for response to post-earthquake conditions postulated here if Containment FCU are available.

A.2.1.2 Support Systems Included in the IPE/IPEEE

Off-Site AC Power

The seismic events considered for the IPEEE are those that are sufficiently large to cause a loss of off-site power. If the seismic event does not cause a loss of off-site power, sufficient systems are assumed to remain available such that the potential for core damage could be considered to be bounded by the internal events PRA.

On-Site AC Power

The on-site AC power system is made up of emergency diesel generators (two per unit) and the plant AC distribution system. (No credit is given in the IPEEE for operation of two non-safeguards diesel generators or the service building AC distribution system.) The AC distribution system is made up of six 4kV buses per unit feeding the large motors, and various 480V load centers. Loss of voltage or degraded voltage on the essential buses will start the emergency diesel generators and initiate load shedding to allow the diesels to supply their respective buses. The Unit 1 and 2 emergency 4KV buses can also be cross-tied to allow the train-related diesel generator on the opposite unit to supply a bus with a failed diesel generator.

DC Power and DC Distribution System

The purpose of this system is to supply an adequate power supply for vital loads such as instrumentation, reactor protection, 4160 V switchgear and EDG control power. No credit is given for the non-safeguards service building DC system. During emergency situations, the station batteries and the DC distribution system are designed to provide power to instruments and controls needed to place the plant in a safe shutdown condition following a loss of all AC power.

Each unit has two complete and separate 125 VDC distribution systems. Each unit has two battery trains and associated power distribution equipment. The combined output of the battery and the battery charger is supplied to the main distribution panel. Individual loads and smaller distribution panels are serviced from the main distribution panel. Non-safeguard equipment is supplied by either battery as appropriate to balance the DC loading on each battery. The success criteria for the DC power system is one train of DC supplied to plant components for two hours through the batteries.

Instrument Air

The Instrument Air system provides dry compressed air to various plant instruments and controls. The system also provides compressed air to operate control valves within various systems. For the seismic IPEEE, the Instrument Air system is conservatively ignored since system piping and supports are distributed throughout the plant and assessment of piping integrity and secondary interactions as a result of the earthquake motion has not been performed.

Cooling Water (CL)

The primary functions of the Cooling Water system are as follows: provide an adequate cooling water supply for plant equipment loads, provide a cooling water supply to all safeguards equipment during nromal and emergency operating conditions, and provide an alternate feedwater supply to the steam generators. Cooling Water is a safeguards system consisting of five pumps feeding a ring header shared by both units. Assuming a loss of offsite power as a result of a seismic event, three of the five pumps (two diesel-driven and one motor-driven) are available to support Cooling Water loads. The Cooling Water header can be automatically or manually separated into two redundant supply headers (headers A and B).

The normal water supply for the CL system is from the circulating water pump bays in the screenhouse. The three vertical safeguards pumps take a suction on an emergency bay and discharge to the common CL header. The emergency bay receives water normally from the circulating water bays through sluice gates, but also has a separate emergency supply intake pipe (36" diameter) which supplies water directly from the Mississippi River. The emergency intake pipe would be required only if the normal path from the Mississippi River through the outer screenhouse were to become blocked. If such blockage were postulated, the cooling water supply would be limited to the inventory in the intake canal plus the flow through the 36" safeguards pipe. As the flow required for two-pump operation exceeds the capacity of the safeguards pipe, operator action to reduce cooling water loads is required. These actions include isolating turbine building loads and containment fan coil units. Given the size of the intake canal, more than four hours are available to reduce and manage Cooling Water loads under these conditions.

The success criteria for the CL system varies depending on the initiating event. For the case of a loss of offsite power (assumed in the case of an earthquake), a single CL pump is required. For a LOCA, a single pump is required assuming that at least one of the CL header isolation valves closes.

120V Instrument AC Power

The 120 V Instrument AC system supplies highly regulated single-phase AC power to plant instrumentation. The system as modeled in the IPE consists of four static inverters which supply four distribution panels, each of which supply power to a separate channel of instrumentation. The static inverters normally are supplied with 480 VAC power from the safeguards 480 V buses. This power supply is backed up by the plant batteries. The inverters then provide an uninterruptable, regulated 120 VAC supply to their corresponding instrument distribution panel.

The distribution panels, also called instrument buses, have two supply breakers which are mechanically interlocked such that only one can be shut at a time. The power supplies are either the associated inverter or panel 117 (217 for Unit 2) which is an unregulated 120 V source.

SI Signal

The safety injection signal ("S" signal) is sent when conditions indicative of a loss of coolant accident exist. The purpose of the signal is to initiate automatic features in the plant designed to prevent core damage and/or mitigate the effects of the accident. The safety injection signal is initiated when any of the following conditions exist:

- Pressurizer pressure less than 1815 psig,
- Containment pressure greater than 4 psig,
- Main steamline pressure in either line less than 500 psig,
- Manual actuation.

The safety injection signal initiates many functions throughout the plant. Some of the more important functions are:

- Reactor Trip signal,
- Start signal to all ECCS pumps and various motor-operated valves receive open or close signals to align ECCS for injection,
- Start signal to both Emergency Diesel Generators,
- Containment FCUs shifted to slow speed and realign to discharge to the containment dome,
- Containment FCUs cooling medium is realigned to Cooling Water,
- Start signal to the Auxiliary Feedwater pumps,
- Cooling water headers split and diesel cooling water pumps receive a start signal.

The seismic IPEEE may rely on some of the automatic actuation features caused by an S signal in response to an earthquake-induced plant condition. However, these features can also be initiated by operator actions in some cases. These situations are noted when reliance has been shifted from automatic to operator-initiated actions.

Safeguards Chilled Water

The Safeguards Chilled Water system consists of two independent trains. Each train is a closed loop chilled water system that consists of a centrifugal chiller, a chilled water pump, and associated piping, valves and unit coolers. Each train supplies room cooling to its associated safeguards equipment including 4160 V and 480 V switchgear, the relay room and computer room, control room air handler, and the RHR pits. Supply and return header cross-connect valves allow either chilled water pump and chiller to supply both trains. The cross-connect valves are automatically shut on an S signal to ensure system reliability.

The success criteria for the system is for one chiller and chilled water pump in a train to be running and supplying chilled water to the Unit 1 4160 V safeguards switchgear room coolers. Analyses were conducted for the 4 kV bus rooms which determined that the critical temperature is reached within one

to two hours following loss of chilled water. Operator actions (i.e., opening the door to the rooms to allow natural circulation to occur) are proceduralized to prevent excedence of the critical temperature.

A.2.1.3 Supporting Components Included in the IPEEE

The seismic IPEEE included distributed systems whose failure could cause a loss of function of the systems listed above, such as piping, cable trays, and conduit. The HVAC ducting need not function to ensure performance of essential systems, but the potential for the HVAC ducting to interfere with other systems during an earthquake was included in the seismic IPEEE.

A.2.2 Plant Walkdown

The objectives of the plant seismic walkdowns were (1) to identify any equipment having sufficiently high seismic capacity that no further review was needed, (2) to identify the potential failure modes and system interactions for equipment that could not be screened from further review, and (3) to obtain data on equipment and structures for use in detailed evaluations of the potential failure modes and system interactions. Preparation for the initial plant walkdown is described in Section A.2.2.1. General descriptions of the initial and final plant walkdowns, including procedures and documentation, are presented in Sections A.2.2.2 and A.2.2.3. Significant walkdown findings are identified in Section A.2.2.4.

A.2.2.1 Pre-Walkdown Preparation

Activities performed prior to the initial plant walkdown included (1) information collection and review, (2) equipment list review, (3) identification of equipment locations, and (4) walkdown data sheet preparation.

Information Collection

Information relevant to the seismic IPEEE was collected. The following categories of plant documentation were obtained prior to and during the plant walkdowns:

- Updated Safety Analysis Report (USAR)
- Structural, architectural, and equipment layout drawings
- Equipment anchorage drawings
- Drawings for selected equipment components
- Specifications for construction of civil structures
- Seismic criteria and analysis reports for building structures
- Geotechnical investigation reports
- I & E Bulletin 80-11 documentation on masonry wall seismic qualification
- Design basis evaluation report on the NSSS Components

This documentation was reviewed prior to the walkdown to obtain an understanding of the plant configuration, design, and construction, vital safety systems, structure response characteristics, and structure and equipment capabilities.

A preliminary listing of all equipment included in the IPE systems model and used for the seismic IPEEE was developed by NSP. Additions and deletions of selected equipment components were suggested by seismic analysts based upon past experience in seismic margins assessment. Further revisions were identified during the walkdown. The essential equipment that was considered in the seismic margins assessment is listed in Tables A.2.3-1 and A.2.4-1.

Components included in the equipment list were located on the mechanical layout drawings to the extent possible. Prior knowledge of equipment locations helped in planning routes through the plant during the walkdown and identification of components in the field. NSP walkdown team members were highly familiar with equipment locations, thus greatly expediting the walkdown.

Walkdown data sheets were prepared for each of the components on the equipment list. To the extent possible, general information was entered into these data sheets by members of the walkdown team before the walkdown. Such information included the equipment class, description, identification number, location (building, floor elevation, and room number), and manufacturer and model number.

A.2.2.2 Initial Plant Walkdown

The initial plant walkdowns were conducted in the Unit 1 containment in June 1994 and in the balance of the plant during November 1994. The June 1994 walkdown was conducted by one walkdown team, while the November 1994 walkdown was performed by two teams. Each walkdown team consisted of two seismic capability engineers and at least one plant engineer. The seismic capability engineers were experienced in the seismic evaluation structures and equipment. The plant engineers participating in the walkdowns were familiar with the functions of the various plant systems, the component layout in the plant, as well as with the PRA model.

Walkdowns in November 1994 were conducted for components in the Auxiliary Building, Turbine Building, Screenhouse, D5/D6 Building, and the Intake Screenhouse. These buildings and their separation gaps, where accessible, were reviewed. In addition, components in the yard outside of the buildings as well as tanks housed in buried concrete vaults were reviewed. Walkdowns were not performed for components within the Unit 2 containment structure as the plant was in operation. Walkdown within the Unit 2 containment was performed in June 1995 as described in Section A.2.2.3.

A.2.2.2.1 Walkdown Procedures

The walkdown followed the procedures recommended by EPRI NP-6041-SL. Walkdown screening of components was conservatively performed following the recommendations of EPRI NP-6041-SL for a review level earthquake having a peak 5% damped spectral acceleration of 0.8g or less. Components were surveyed in the walkdown to ensure that caveats implicit in the screening criteria were satisfied.

Structures

Data required for screening or seismic margin assessment of civil structures are typically obtained from design drawings rather than from walkdowns. A complete set of structural drawings was reviewed to develop a general understanding of the building construction and configuration as well to identify any data to be obtained in the walkdown. The walkdown was performed to (1) verify that the structures are

generally in conformance with the design drawings, (2) identify any gross deficiencies that might affect the structure capacities, and (3) confirm that separations between the buildings are consistent with the design drawings.

Masonry Walls

Masonry walls supporting or in proximity to essential equipment were identified on equipment walkdown data sheets as potential seismic interaction concerns. Documentation on the Prairie Island masonry wall evaluations performed in response to USNRC I&E Bulletin 80-11 was reviewed to obtain an understanding of the block wall construction, configuration, and seismic capacity.

Equipment and Vessels

The initial plant walkdown surveyed components in accessible areas. Detailed inspections were performed for numerous components. Other components, while not inspected in detail, were determined to be similar to those for which detailed inspections were performed. Sufficient reviews were performed to establish that similarities exist in terms of component construction and anchorage. Any component specific features, such as anchorage details or system interaction issues, were recorded.

Key elements of the component walkdowns included review of component configuration and construction, anchorage, and potential system interactions. These reviews followed the walkdown guidelines of EPRI NP-6041-SL.

Configuration and construction details of the components and their supports were reviewed to ensure structural integrity and post-earthquake functionality. Following checklists on the walkdown data sheets, components were inspected to ensure that they possessed adequate seismic design features. These included attributes such as adequate stiffness and strength of seismic load paths and adequate attachment for appurtenances. Components were also inspected to identify any seismic vulnerabilities, such as unreinforced cabinet cutouts, unrestrained vibration isolators, and excessive component or attachment weight.

Inspection of component anchorage included verifying that the load paths have adequate stiffness and identification of any specific concerns, such as high shims or excessive concrete cracking in the vicinity of the anchor. Screening of anchorage strength for most components was deferred until after the initial plant walkdown, at which time SQUG component anchorage calculations were reviewed and additional quantitative evaluations were performed. Data on component anchorage were recorded for use in these evaluations.

Inspection was performed to identify any systems interaction concerns associated with proximity, Class II-over-Class I interactions, and spray and flooding. Essential components in close proximity to adjacent objects were reviewed for potential damage due to relative seismic motion. Only soft targets, such as gauges or small tubing, were considered vulnerable to impact damage. Electrical cabinets potentially containing essential relays were also identified for possible impact induced relay chatter. Any Class II-over-Class I interactions associated with a non-essential component falling on an essential component were identified. Potential Class II-over-Class I interactions include failure of

concrete block walls or ceiling systems. Any credible sources of spray or flooding that could impair the function of an essential component were identified. Potential sources of spray and flooding include failure of wet fire water piping with threaded joints or mechanical couplings and non-essential tanks. If such sources were identified, further review was performed to identify any mitigating features, such as spray shields or floor drains.

NUREG-1407 guidance for relay evaluation is to follow SQUG procedures for a plant such as Prairie Island that is required to address USI A-46 [U.S. Nuclear Regulatory Commission, 1987]. Consequently, no relay walkdown was performed for the Prairie Island IPEEE, but instead was deferred to the SQUG review.

Distributed Systems

Distributed systems reviewed in the walkdown included piping, cable trays, and conduit. General surveys of these systems were performed during the walkdowns to identify the presence of any seismic vulnerabilities. HVAC ductwork is not required for room cooling. However, HVAC duct work in proximity to essential components were reviewed for potential system interaction concerns.

A.2.2.2.2 Walkdown Documentation

Documentation of the walkdown consisted of data sheets, photographs, and field notes for the equipment and structures surveyed. Walkdown data sheets following the formats recommended in EPRI NP-6041-SL were used. These data sheets vary according to the generic equipment component category. They contain checklists of seismic adequacy issues to be addressed in the inspection of a component and the data sheets include space to record additional notes and sketches. Photographs were taken to supplement any notes or details taken during the walkdown. For a component, photos of the overall configuration, anchorage, and any other notable features or systems interactions were typically taken.

A.2.2.3 Final Plant Walkdowns

Subsequent walkdowns were conducted in June 1995 and in October 1996. Both walkdowns were performed by a team consisting of two seismic capability engineers and at least one plant engineer. Components that were reviewed in the June 1995 walkdown included those within the Unit 2 containment, which was in an outage at that time. In the final walkdown during October 1996, reviews were conducted to gather additional data for seismic evaluation and to resolve certain open issues.

A.2.2.4 Findings from the Plant Walkdowns

Significant findings from the plant walkdowns are summarized below. The potential seismic concerns discussed in Section A.2.4.

Structures

Building separation gaps were reviewed in the field, where accessible. The gaps appeared consistent with the details noted on the structural drawings.

Concrete Block Walls

Block walls posing potential seismic interaction hazards to essential equipment were typically found to be safety- related walls previously evaluated in the I&E 80-11 program. Some non-safety related walls were identified as interaction concerns. These non-safety related walls were addressed by comparisons to bounding safety-related walls.

Mechanical Equipment

CV-31059 and CV - 31060 : Trip and Throttle Valves for 11 and 22 Turbine Driven Auxiliary Feedwater Pumps. Each valve has a trip device which may be vibration- sensitive. An earthquake-induced trip was judged to be credible.

CV-39401 and CV-39409 FCU ,#11 FCU Cooling Water Supply and #12/#14 FCU Cooling Water Return Valves: Seismic interactions were identified since the valve operators contact adjacent conduit. Failure of the solenoid connection could occur due to relative displacements between the valves and conduit.

CV-39411 #11/#13 FCU Cooling Water Return Valve: A limit switch on the valve operator touches the limit switch for an adjacent valve mounted on another pipe. Seismic- induced motion may damage the limit switch.

121 and 122 Control Room Chillers: These chillers are supported by unrestrained vibration isolators.

12 and 22 Diesel Driven Cooling Water Pumps and 121 Cooling Water Pump: Anchor bolts for these pumps do not satisfy minimum edge distance requirements and the vertical shaft lengths exceed the maximum length identified by the component caveats.

Electrical Equipment

12 and 22 Batteries: Missing spacers were noted in the battery racks.

D1 and D2 Diesel Generator Gage Panels: Both panels are supported with very flexible, unrestrained vibration isolators.

D2 Diesel Generator Control Panel: Scaffolding was found to be hung on wall hooks behind the panel. Should the scaffolding fall off the hooks due to earthquake motion, impact with the control panel could cause relay chatter. Damage to the panel and its anchorage due to impact by the scaffolding is unlikely.

DC Panels 11, 12, and 22: Bases of these panels are elevated above the floor which would result in seismic-induced bending stresses in the anchorage.

4160V Bus 25: A wall-mounted ladder was found to be located behind the cabinet. Should the ladder fall off the wall-hooks due to earthquake motion, impact with the bus cabinet could cause relay chatter. Damage to the cabinet and its anchorage by the ladder is unlikely.

MCC 1K1: "RHR Lifting Block Fixtures" were found to be mounted on the wall behind the MCC. Should these items fall off the wall-hooks, impact with the MCC could cause relay chatter. Damage to the MCC and its anchorage due to impact is unlikely.

MCC 1L2 : A rod hung pipe is located close to the cables feeding into the top of the MCC. The pipe could swing due to earthquake motion and strike the cables, potentially resulting in relay chatter. Damage to the MCC cabinet and its anchorage is unlikely.

MCC 2K2: A rod hung pipe is located close to the MCC cabinet. The pipe could swing due to earthquake motion. Impact between the pipe and the MCC could cause relay chatter. Damage to the MCC and its anchorage is unlikely.

MCC 1TA1 and MCC 1TA2: Both MCCs are supported on high shims which will lead to seismic-induced anchor bolt bending.

MCC 2LA2: The welded anchorage is very minimal.

Tanks and Heat Exchangers

12 and 22 Jacket Heat Exchangers for 12 and 22 Diesel Cooling Water Pump Engines: No structural connection between the heat exchanger vessel and the saddle supports was observed.

11, 12, and 22 Condensate Storage Tanks: Anchorage for the 12 and 22 condensate storage tanks includes epoxied anchor bolts, which are considered outliers by the GIP criteria. Anchorage for the 11 condensate storage tank includes a combination of cast-in-place anchor bolts and concrete expansion anchors. The expansion anchors may not have adequate seismic capacity.

Distributed Systems

The essential piping, cable trays, conduit, and HVAC ductwork were found to be seismically adequate.

Other

Seismic vulnerabilities were identified for the control room ceiling. The diffuser panels represent falling hazards which may strike the main control panels.

Additional generic observations included potential seismic interaction hazards due to overhead fluorescent lights hung with open S-hooks and ladders hung on wall hooks. Should either the lights or the ladders fall due to earthquake motion, impact with the essential component could cause relay chatter. Damage to the components and their anchorage is unlikely. The open S-hooks could be corrected by crimping them closed. This activity was identified as part of the outlier resolutions of the SQUG program. Therefore, no further review was conducted for the overhead lights. Components with interactions from wall hung ladders were identified for further review. The placement of the ladders appeared to be transient as they were not always found in the same locations in subsequent walkdowns.

A.2.3 Component Screening

Components identified in the walkdowns to be seismically rugged were screened from further review following the walkdown guidelines of EPRI NP-6041-SL. This walkdown screening was conservatively performed using focused scope plant criteria.

Following issuance of Supplement 5 to Generic Letter 88-20, further component and structure screening was performed following NUREG 1407guidelines for reduced scope plants. Seismic input for this screening consisted of the ground and in-structure SSE response spectra at 0.12g. Equipment and vessels were screened using the criteria of the GIP. Component screening used the results of the SQUG program supplemented with quantitative evaluations of bounding cases. These bounding calculations were typically performed using conservative approximations and input in order to screen components from further detailed analysis. Structures and components outside the SQUG scope for which the GIP criteria are not applicable (e.g., civil structures, masonry walls, and NSSS components) were screened to the SSE level using USAR requirements.

A.2.3.1 Structure Screening

The following structures were found not to need more detailed analyses:

- *A.* ***Shield Buildings***
- ***B. Containment Vessels***
- ***C. Auxiliary Building***
- ***D. Portions of the Turbine Building housing Class I equipment***
- ***E. Screenhouse***
- ***F. D5/D6 Building***

All of the above structures are identified as Class I structures in the Prairie Island USAR. All were designed using dynamic analyses for an SSE with a peak ground acceleration of 0.12g. The auxiliary building, turbine building (areas housing Class I equipment), screenhouse, and the D5/D6 building all have seismic load resisting systems comprised of reinforced concrete shear walls, floor diaphragms, and foundations. The shield buildings are reinforced concrete each consisting of a cylindrical shell capped with a dome and supported on a reinforced concrete mat foundation. The Unit 1 and Unit 2 containment vessels are free-standing steel containment structures which are embedded in the foundation mats. Also, a review of the building structural drawings identified no significant seismic vulnerabilities. Thus, the structures were screened from further review based on the design basis USAR criteria.

A.2.3.2 Concrete Block Wall Screening

Masonry walls identified in the walkdown to pose credible seismic interaction hazards to essential equipment typically consisted of safety related walls. A few non-safety related walls were identified as seismic interaction concerns. These non-safety walls are bounded by other safety related walls. The safety-related walls were previously evaluated and upgraded for seismic adequacy to the SSE level in the I&E 80-11 program. Since masonry walls are outside of the SQUG program scope and the GIP is not applicable, they were consequently screened using SSE seismic input and the requirements of the

USAR. Screening of the masonry walls was based on a review of the documentation for the I&E 80-11 evaluations. Based on this review, the masonry walls were concluded to be seismically adequate to the SSE and were screened from further review.

A.2.3.3 Component Screening

Components that were screened from further review are listed in Table A.2.3-1. Components on this table have been screened at the SSE or higher. General comments on these components are listed below. The remaining components, for which further analysis was needed, are discussed in greater detail in Section A.2.4.

Mechanical Equipment

Most mechanical equipment was verified to be adequate to retain structural integrity and post-earthquake functionality based on the walkdowns. Most mechanical components could be screened from further review based on the results of the SQUG program. For components within the SQUG scope, bounding cases were identified for the different equipment categories and the corresponding SQUG evaluations were reviewed to confirm concurrence between the IPEEE and SQUG assessments. For components outside of the SQUG program, anchorage evaluations were performed using bounding cases of different generic component categories using the criteria of the GIP. For example, horizontal pumps were screened by evaluating the anchorage of a bounding case pump. The bounding pump anchorage was found to be adequate. Consequently, all of the horizontal pumps enveloped by the bounding case were screened from further review.

A few mechanical components were flagged for seismic concerns due to system interactions or conditions not satisfying the equipment screening caveats as noted in the walkdowns. These components were identified for further review.

Electrical Equipment

Most electrical equipment was verified to be adequate to retain structural integrity and post-earthquake functionality based on the walkdowns. Most of the electrical components were screened from further review based on the results of the SQUG program.

Electrical equipment identified for further review included components with seismic interaction concerns or that had conditions which did not satisfy the equipment screening caveats.

Tanks and Heat Exchangers

Most tanks and heat exchangers were screened from further review based on the results of the SQUG program, the walkdowns, and bounding calculations. For vessels outside of the SQUG program, evaluations of bounding cases were performed using the criteria of the GIP. For example, the vertical tanks outside the scope of SQUG were grouped together. Evaluating and confirming the adequacy of the bounding case allowed for all of the tanks in the group to be screened from further review.

Distributed Systems

Walkdown of representative lines verified that essential piping is seismically adequate and could be screened from further review. With the exception of a few valves with identified system interaction concerns, the valves were screened from further review based on the walkdown data.

Cable trays and conduit were verified to be seismically adequate based on walkdowns of representative samples and the results of the SQUG evaluation. The SQUG evaluation included the selection and review of representative bounding cases. These bounding cases were found to be adequate and, thus, cable trays and conduit were screened from further review.

HVAC ducting is not required for room cooling in support of essential systems for IPEEE. Therefore, HVAC ductwork was only reviewed as potential seismic system interaction concerns for essential equipment. HVAC ductwork is typically rod-hung and was found to be seismically adequate based on the walkdowns of representative samples.

A.2.3.4 Relay Screening

Because Prairie Island is subject to USI A-46 [4] requirements, the evaluation of relay chatter at Prairie Island was conducted following SQUG procedures. The Prairie Island SQUG Program has determined that Prairie Island does have some relays that are considered to have low seismic ruggedness. This is documented in the Prairie Island USI A-46 report [25]. According to NUREG- 1407, plants under the Reduced Scope bin have no actions to consider for the IPEEE; i.e., the USI A-46 review is considered sufficient. Plants in the Focused Scope bin also follow the USI A-46 program, unless low seismic ruggedness relays are discovered as part of USI A-46. The evaluation of relay chatter for Prairie Island was therefore expanded to include relays outside of the scope of the SQUG program but within the scope of the IPEEE, consistent with Section 3.2.4.2 of NUREG-1407. An initial identification and functional screening of the relays was done in order to acquire an understanding of the potential effect of relay chatter.

The evaluation for the seismic IPEEE proceeded by identifying the relays appropriate for the IPEEE models, beginning with the IPE. The seismic IPEEE considers the potential for a both a loss of offsite power and small LOCA. The IPEEE models were configured to describe the availability of plant systems and components under these postulated conditions following the seismic event. Table A.2.3-2 provides the summary of relays credited in the seismic IPEEE but not in the SQUG Relay Evaluation Report [25]. The set of relays credited by the seismic IPEEE that are not in the SQUG program were reviewed to determine if any were potential outliers from the list of Low Ruggedness Relays in EPRI NP-7148-SL, Appendix E [13]. None of these relays is on the low ruggedness relay list. Therefore, of the relays credited in the seismic IPEEE, most relays are within the scope of the SQUG program, with all remaining relays having been determined to not be on the "bad actors" list.

Table A.2.3-1 Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
11 INVERTER	11 INVERTER	AC 120
12 INVERTER	12 INVERTER	AC 120
13 INVERTER	13 INVERTER	AC 120
17 INVERTER	17 INVERTER	AC 120
18 INVERTER	18 INVERTER	AC 120
PANEL 111	PNL 111	AC 120
PANEL 112	PNL 112	AC 120
PANEL 113	PNL 113	AC 120
PANEL 114	PNL 114	AC 120
PANEL 134	PNL 134	AC 230
PANEL 134 PHASE A 240/120V TRANSFORMER	PNL 134/A XFMR	AC 230
PANEL 134 PHASE B 240/120V TRANSFORMER	PNL 134/B XFMR	AC 230
PANEL 134 PHASE C 240/120V TRANSFORMER	PNL 134/C XFMR	AC 230
PANEL 135	PNL 135	AC 230
PANEL 135 PHASE A 240/120V TRANSFORMER	PNL 135/A XFMR	AC 230
PANEL 135 PHASE B 240/120V TRANSFORMER	PNL 135/B XFMR	AC 230
PANEL 135 PHASE C 240/120V TRANSFORMER	PNL 135/C XFMR	AC 230
PANEL 136	PNL 136	AC 230
PANEL 136 PHASE A 240/120V TRANSFORMER	PNL 136/A XFMR	AC 230
PANEL 136 PHASE B 240/120V TRANSFORMER	PNL 136/B XFMR	AC 230
PANEL 136 PHASE C 240/120V TRANSFORMER	PNL 136/C XFMR	AC 230
PANEL 137	PNL 137	AC 230
PANEL 137 PHASE A 240/120V TRANSFORMER	PNL 137/A XFMR	AC 230
PANEL 137 PHASE B 240/120V TRANSFORMER	PNL 137/B XFMR	AC 230
PANEL 137 PHASE C 240/120V TRANSFORMER	PNL 137/C XFMR	AC 230
BREAKER POSITION INDICATOR 52A/16-4	52A/16-4	AC 4160
BREAKER POSITION RELAY 52A/15-4	52A/15-4	AC 4160
BUS 15	BUS 15	AC 4160
BUS 15 LOAD SEQUENCE CABINET	BUS 15 CABINET	AC 4160
BUS 15 LOGIC RELAY CABINET		AC 4160
BUS 16	BUS 16	AC 4160
BUS 16 LOAD SEQUENCE CABINET	BUS 16 CABINET	AC 4160
BUS 16 LOGIC RELAY CABINET		AC 4160
BUS 111 480V	BUS 111M	AC 480
BUS 112 480V	BUS 112M	AC 480
BUS 121 480V	BUS 121	AC 480
BUS 122 480V	BUS 122	AC 480
MCC 1A BUS 1	MCC 1A BUS 1	AC 480
MCC 1A BUS 2	MCC 1A BUS 2	AC 480
MCC 1AC BUS 1	MCC 1AC BUS 1	AC 480
MCC 1AC BUS 2	MCC 1AC BUS 2	AC 480
MCC 1K BUS 2	MCC 1K BUS 2	AC 480
MCC 1KA2	MCC 1KA2	AC 480
MCC 1L BUS 1	MCC 1L BUS 1	AC 480
MCC 1LA1	MCC 1LA1	AC 480
MCC 1LA2	MCC 1LA2	AC 480
MCC 1T BUS 1	MCC 1T BUS 1	AC 480
MCC 1T BUS 2	MCC 1T BUS 2	AC 480
MCC 1X1	MCC 1X1	AC 480

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
MCC 1X2	MCC 1X2	AC 480
11 SG LEVEL TRANSMITTER 1LT-461	1LT-461	AF
11 SG LEVEL TRANSMITTER 1LT-462	1LT-462	AF
11 SG LEVEL TRANSMITTER 1LT-463	1LT-463	AF
11 TDAFWP RELAY CABINET A1640	TB A1640	AF
11 TURBINE DRIVEN AF PUMP	22 TD AFW PUMP	AF
12 MOTOR DRIVEN AF PUMP	12 MD AFW PUMP	AF
12 SG LEVEL TRANSMITTER 1LT-471	1LT-471	AF
12 SG LEVEL TRANSMITTER 1LT-472	1LT-472	AF
12 SG LEVEL TRANSMITTER 1LT-473	1LT-473	AF
CHECK VALVE AF-14-1 -- CD TO 11 AF PUMP SUCTION	AF-14-1	AF
CHECK VALVE AF-14-3 -- CD TO 12 AF PUMP SUCTION	AF-14-3	AF
CHECK VALVE AF-15-1 -- 11 AF TO 11 SG	AF-15-1	AF
CHECK VALVE AF-15-10 -- 12 AF PUMP DISCHARGE	AF-15-10	AF
CHECK VALVE AF-15-2 -- 11 AF TO 12 SG	AF-15-2	AF
CHECK VALVE AF-15-3 -- 12 AF TO 11 SG	AF-15-3	AF
CHECK VALVE AF-15-4 -- 12 AF TO 12 SG	AF-15-4	AF
CHECK VALVE AF-15-9 -- 11 AF PUMP DISCHARGE	AF-15-9	AF
CHECK VALVE AF-16-1 -- AF TO 11 SG	AF-16-1	AF
CHECK VALVE AF-16-2 -- AF TO 12 SG	AF-16-2	AF
CHECK VALVE RS-15-1	RS-15-1	AF
CHECK VALVE RS-15-2	RS-15-2	AF
CV-31153 -- 11 TD AFW PUMP RECIRC/LUBE OIL CLNG VALVE	CV-31153	AF
CV-31154 -- 12 MD AFW PUMP RECIRC/LUBE OIL CLNG VALVE	CV-31154	AF
CV-31998 -- MS SUPPLY TO 11 TD AFW PUMP	CV-31998	AF
LIMIT SWITCH 33AC-31998 (on Valve)	33AC-31998	AF
MANUAL VALVE AF-13-1 ON CROSS TIE BETWEEN 12 & 21 AF PUMPS	AF-13-1	AF
MV-32016 -- 11 SG STEAM TO 11 TD AFW PUMP	MV-32016	AF
MV-32017 -- 12 SG STEAM TO 11 TD AFW PUMP	MV-32017	AF
MV-32025 -- CL TO 11 TD AF PUMP SUCTION	MV-32025	AF
MV-32027 -- CL TO 12 MD AF PUMP SUCTION	MV-32027	AF
MV-32238 -- 11 TD AF PUMP TO 11 SG	MV-32238	AF
MV-32239 -- 11 TD AF PUMP TO 12 SG	MV-32239	AF
MV-32333 -- CONDENSATE TO SUCTION OF 11 AF PUMP	MV-32333	AF
MV-32335 -- CONDENSATE TO SUCTION OF 12 AF PUMP	MV-32335	AF
MV-32381 -- 12 AF PUMP TO 12 SG	MV-32381	AF
MV-32382 -- 12 AF PUMP TO 11 SG	MV-32382	AF
PRESSURE SWITCH PS-17700 (11 AF PUMP DISCHARGE)	PS-17700	AF
PRESSURE SWITCH PS-17704 (11 AF PUMP SUCTION)	PS-17704	AF
PRESSURE SWITCH PS-17776 (12 AF PUMP SUCTION)	PS-17776	AF
PRESSURE SWITCH PS-17777 (12 AF PUMP DISCHARGE)	PS-17777	AF
11 CC HEAT EXCHANGER	11 CC HX	CC
11 CC PUMP	145-121	CC
11 CC SURGE TANK	11 CC SURGE TANK	CC
12 CC HEAT EXCHANGER	135-032	CC
12 CC PUMP	145-122	CC
CHECK VALVE CC-14-5 -- 11 RCP BEARING CC WATER RTN	CC-14-7	CC
CHECK VALVE CC-14-6 -- 12 RCP BEARING CC WATER RTN	CC-14-6	CC
CHECK VALVE CC-18-1 -- 12 RCP BEARING CC SUPPLY	CC-18-1	CC

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
CHECK VALVE CC-18-2 -- 11 RCP BEARING CC SUPPLY	CC-18-2	CC
CHECK VALVE CC-29-1 -- 12 RCP TBHX CC IN	CC-29-1	CC
CHECK VALVE CC-29-2 -- 11 RCP TBHX CC IN	CC-29-2	CC
CHECK VALVE CC-3-1 -- 11 CC PUMP DISCHARGE	CC-3-1	CC
CHECK VALVE CC-3-2 -- 12 CC PUMP DISCHARGE	CC-3-2	CC
CHECK VALVE CC-5-1 -- RETURN LINE TO 11 CC PUMP	CC-5-1	CC
CHECK VALVE CC-5-2 -- RETURN LINE TO 12 CC PUMP	CC-5-2	CC
CHECK VALVE CC-61-1 -- TR. B SUPPLY TO 11/12 RCP BRG CLG	CC-61-1	CC
CHECK VALVE CC-61-2 -- TR. A SUPPLY TO 11/12 RCP BRG CLG	CC-61-2	CC
MV-32093 -- 11 RHR HEAT EXCHANGER INLET	MV-32093	CC
MV-32094 -- 12 RHR HEAT EXCHANGER INLET	MV-32094	CC
MV-32200 -- CC SURGE TANK TO 11 CC PUMP	MV-32200	CC
MV-32201 -- CC SURGE TANK TO 12 CC PUMP	MV-32201	CC
MV-32266 -- TR. A CC SUPPLY TO 11/12 RCP	MV-32266	CC
11 CLG WTR STRAINER	158-011	CL
11 DIESEL COOLING SUPPLY FAN		CL
11 SCREENHOUSE DIESEL COOLING SUPPLY FAN		CL
12 AIR RECEIVERS A/B FOR 12 CLG WATER PUMP		CL
12 CL DAY TANK LEVEL (HIGH) SWITCH LA-16683	LA-16683	CL
12 CLG WTR. STRAINER	158-012	CL
12 DIESEL COOLING WATER PUMP CONTROL PANEL		CL
12 DIESEL GENERATOR FOR 12 CLG WATER PUMP		CL
121 EMERGENCY BYPASS GATE	121 BYPASS GATE	CL
121 INTAKE SCREEN BYPASS GATE HYDRAULIC ACCUM.		CL
121 S.H. INTAKE BYPASS DRIVE UNIT		CL
121 SFGD TRAVELLING SCREEN	121 TRAV. SCREEN	CL
122 EMERGENCY BYPASS GATE	122 BYPASS GATE	CL
122 INTAKE SCREEN BYPASS GATE HYDRAULIC ACCUM.		CL
122 S.H. INTAKE BYPASS DRIVE UNIT		CL
122 SFGD TRAVELLING SCREEN	122 TRAV. SCREEN	CL
CHECK VALVE CL-43-2 -- 12 CL PUMP DISCHARGE	CL-43-2	CL
CHECK VALVE CL-43-3 -- 121 CL PUMP DISCHARGE	CL-43-3	CL
CHECK VALVE CW-12-1 -- 11 FCU CL INLET	CW-12-1	CL
CHECK VALVE CW-12-2 -- 13 FCU CL INLET	CW-12-2	CL
CHECK VALVE CW-12-3 -- 12 FCU CL INLET	CW-12-3	CL
CHECK VALVE CW-12-4 -- 14 FCU CL INLET	CW-12-4	CL
CL-95-1 -- U1 CL PRESSURE REDUCING GOVERNOR VALVE	CL-95-1	CL
CV-39403 -- 12/14 FCU COOLING WATER SUPPLY VALVE	CV-39403	CL
D1 COOLING WATER INLET VALVE CV-31505	CV-31505	CL
D2 COOLING WATER INLET VALVE CV-31506	CV-31506	CL
MV-32034 -- CL PUMP DISCHARGE HDR VALVE A	MV-32034	CL
MV-32035 -- CL PUMP DISCHARGE HDR VALVE B	MV-32035	CL
MV-32132 -- 11 FCU CL OUTLET ISOL A	MV-32132	CL
MV-32133 -- 11 FCU CL OUTLET ISOL B	MV-32133	CL
MV-32135 -- 12 FCU CL OUTLET ISOL A	MV-32135	CL
MV-32136 -- 12 FCU CL OUTLET ISOLATION B	MV-32136	CL
MV-32138 -- 13 FCU CL OUTLET ISOL A	MV-32138	CL
MV-32139 -- 13 FCU CL OUTLET ISOL B	MV-32139	CL
MV-32141 -- 14 FCU CL OUTLET ISOL A	MV-32141	CL
MV-32142 -- 14 FCU CL OUTLET ISOLATION B	MV-32142	CL

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
MV-32145 -- 11 CC HX COOLING WATER INLET	MV-32145	CL
MV-32146 -- 12 CC HX COOLING WATER INLET	MV-32146	CL
MV-32322 -- LOOP A/B CL RETURN HDR CROSSOVER VALVE	MV-32322	CL
MV-32329 -- AB LOOP A/B CL RETURN HDR CROSSOVER VALVE	MV-32329	CL
MV-32377 -- 11 FCU CL INLET	MV-32377	CL
MV-32378 -- 13 FCU CL INLET	MV-32378	CL
MV-32379 -- 12 FCU CL INLET	MV-32379	CL
MV-32380 -- 14 FCU CL INLET	MV-32380	CL
CONTROL ROOM CONTROL PANEL A	PNL A	CRM
CONTROL ROOM CONTROL PANEL B	PNL B	CRM
CONTROL ROOM CONTROL PANEL C	PNL C	CRM
CHECK VALVE CS-16 -- 11 CS PUMP SUCTION LINE	CS-16	CS
CHECK VALVE CS-17 -- 12 CS PUMP SUCTION LINE	CS-17	CS
CHECK VALVE CS-18 -- 11 CS PUMP DISCHARGE TO SPRAY RINGS	CS-18	CS
CHECK VALVE CS-19 -- 12 CS PUMP DISCHARGE TO SPRAY RINGS	CS-19	CS
MV-32096 -- 11 CS PUMP SUCTION FROM 11 RHR HX	MV-32096	CS
MV-32097 -- 12 CS PUMP SUCTION FROM 12 RHR HX	MV-32097	CS
MV-32098 -- 11 CS PUMP SUCTION FROM 1 RWST	MV-32098	CS
MV-32099 -- 12 CS PUMP SUCTION FROM 1 RWST	MV-32099	CS
MV-32103 -- 11 CS PUMP DISCHARGE VALVE	MV-32103	CS
MV-32105 -- 12 CS PUMP DISCHARGE VALVE	MV-32105	CS
11 BATTERY CHARGER	11 BTTRY CHRGR	DC
11 BATTERY DISCONNECT		DC
12 BATTERY CHARGER	12 BTTRY CHRGR	DC
12 BATTERY DISCONNECT	12-31 DC BT	DC
PANEL 12	PNL 12	DC
PANEL 15	PNL 15	DC
PANEL 151	PNL 151	DC
PANEL 152	PNL 152	DC
PANEL 16	PNL 16	DC
PANEL 161	PNL 161	DC
PANEL 162	PNL 162	DC
PANEL 163	PNL 163	DC
PANEL 17	PNL 17	DC
PANEL 18	PNL 18	DC
PANEL 191	PNL 191	DC
121/122 OUTSIDE EXHAUST FANS		DG
CD-34049 TRN A DAMPERS -- 121/122 DG ROOM OUTSIDE AIR	CD-34049	DG
CD-34049 TRN B DAMPERS -- 121/122 DG ROOM OUTSIDE AIR	CD-34049	DG
D1 D.G. AIR EXHAUST MUFFLER		DG
D1 DAY TANK LEVEL SWITCH 71X/16698	71X/16698	DG
D1 DG AIR INTAKE FILTER SILENCER		DG
D1 DG CONTROL PANEL	D1 DG CON. PANEL	DG
D1 DG EXPANSION LEVEL TANK		DG
D1 DG SKID PANEL	D1 SKID PANEL	DG
D1 DIESEL GENERATOR	034-011	DG
D1 DIESEL GENERATOR 121 EXHAUST FAN	D1 DG 121 FAN	DG
D1 DIESEL GENERATOR 121 SUPPLY FAN	D1 DG 121 FAN	DG
D1 DSL GEN. RESERVE & MAIN AIR RCVR. TANKS	046-031	DG
D1 E.G. INTAKE AIR SILENCER		DG

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
D1 FO DAY TANK	D1 FO DAY TANK	DG
D1 RELAY PANEL	D1 RELAY PANEL	DG
D2 D.G. AIR EXHAUST MUFFLER		DG
D2 DAY TANK LEVEL SWITCH 71X/16699	71X/16699	DG
D2 DG AIR INTAKE FILTER SILENCER		DG
D2 DG EXPANSION LEVEL TANK		DG
D2 DG SKID PANEL	D2 DG SKID PANEL	DG
D2 DIESEL GENERATOR	D2 DIESEL GEN.	DG
D2 DIESEL GENERATOR 122 EXHAUST FAN	D2 DG 122 FAN	DG
D2 DIESEL GENERATOR 122 SUPPLY FAN	D2 DG 122 FAN	DG
D2 DIESEL GENERATOR 122 SUPPLY FAN BREAKER 123-38	D2 DG BREAKER	DG
D2 DSL GEN. RESERVE & MAIN AIR RCVR. TANKS		DG
D2 E.G. INTAKE AIR SILENCER		DG
D2 E.G. INTAKE AIR SILENCER		DG
D2 FO DAY TANK	D2 FO DAY TANK	DG
D2 RELAY PANEL	D2 RELAY PANEL	DG
TB 1203 AUX RELAY CABINET	TB 1203	ED
TB 1208 RELAY CABINET	TB 1208	ED
TB 1209 -- RELAY ROOM TERMINAL BOX	TB 1209	ED
TB 1215 RELAY CABINET	TB 1215	ED
PANEL 1EMA	PNL 1EMA	EM
PANEL 1EMB	PNL 1EMB	EM
121 CL FUEL OIL TRANSFER PUMP	121 CL FOTP	FO
121 CL FUEL OIL TRANSFER PUMP	121 CL FOTP	FO
121 FP FUEL OIL TRANSFER PUMP	121 F.W. FOTP	FO
121 FUEL OIL TRANSFER PUMP	121 FOTP	FO
122 CL FUEL OIL TRANSFER PUMP	122 CL FOTP	FO
122 FUEL OIL TRANSFER PUMP	122 FOTP	FO
123 FUEL OIL TRANSFER PUMP	123 FOTP	FO
124 FUEL OIL TRANSFER PUMP	124 FOTP	FO
CHECK VALVE AT OUTLET OF 121 CL FOTP	121 CL OUTLET CV	FO
CHECK VALVE AT OUTLET OF 121 FOTP	121 OUTLET CV	FO
CHECK VALVE AT OUTLET OF 122 CL FOTP	122 CL OUTLET CV	FO
CHECK VALVE AT OUTLET OF 122 FOTP	122 OUTLET CV	FO
CHECK VALVE AT OUTLET OF 123 FOTP	123 OUTLET CV	FO
CHECK VALVE AT OUTLET OF 124 FOTP	124 OUTLET CV	FO
12 STM GEN LOOP B WR LVL XMTR	1LT-470	MS
12 STM GEN LOOP B WR LVL XMTR	1LT-488	MS
12 STM GEN LOOP B WR LVL XMTR	1LT-503	MS
CV-31084 -- 11 SG PORV	CV-31084	MS
CV-31089 -- 12 SG PORV	CV-31089	MS
CV-31098 -- 11 SG MAIN STEAM ISOLATION VALVE	CV-31098	MS
CV-31099 -- 12 SG MAIN STEAM ISOLATION VALVE	CV-31099	MS
MN STM FR 11 STM GEN CHNNL I RED F XMTR	1FT-464	MS
MN STM FR 11 STM GEN CHNNL II WHITE F XMTR	1FT-465	MS
MN STM FR 12 STM GEN CHNNL III BLUE F XMTR	1FT-474	MS
MN STM FR 12 STM GEN CHNNL IV YEL F XMTR	1FT-475	MS
CV-31231 -- 1 PZR PORV B CONTROL VALVE	CV-31231	RC
CV-31232 -- 1 PZR PORV A CONTROL VALVE	CV-31232	RC
MV-32195 -- 1 PZR PORV A BLOCK VALVE	MV-32195	RC

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
MV-32196 -- 1 PZR PORV B BLOCK VALVE	MV-32196	RC
TRAIN A HOT SHUTDOWN PANEL	51000	RC
11 RHR HEAT EXCHANGER	11 RHR HX.	RH
11 RHR PUMP	11 RHR PUMP	RH
12 RHR HEAT EXCHANGER	12 RHR HX.	RH
12 RHR PUMP	12 RHR PUMP	RH
1RCS1	1RCS1	RH
1RCS2	1RCS2	RH
CHECK VALVE RH-3-1 -- 12 RHR PUMP SUCTION LINE	RH-3-1	RH
CHECK VALVE RH-3-2 -- 11 RHR PUMP SUCTION LINE	RH-3-2	RH
CHECK VALVE RH-3-3 -- 12 RHR PUMP DISCHARGE LINE	RH-3-3	RH
CHECK VALVE RH-3-4 -- 11 RHR PUMP DISCHARGE LINE	RH-3-4	RH
CV-31235 -- 11 RHR HEAT EXCHANGER OUTLET CV	CV-31235	RH
CV-31236 -- 12 RHR HEAT EXCHANGER OUTLET CV	CV-31236	RH
MV-32064 -- 1 RHR TO RX VESSEL TRN A	MV-32064	RH
MV-32065 -- 1 RHR TO RX VESSEL TRN B	MV-32065	RH
MV-32066 -- 1 RHR RETURN TO LOOP B COLD LEG (SDC)	MV-32066	RH
MV-32084 -- 1 RWST TO 11 RHR PUMP	MV-32084	RH
MV-32085 -- 1 RWST TO 12 RHR PUMP	MV-32085	RH
MV-32164 -- 1 LOOP A HOT LEG TO RHR TRN A	MV-32164	RH
MV-32165 -- 1 LOOP A HOT LEG TO RHR TRN B	MV-32165	RH
MV-32230 -- 1 LOOP B HOT LEG TO RHR TRN A	MV-32230	RH
MV-32231 -- 1 LOOP B HOT LEG TO RHR TRN B	MV-32231	RH
PRESSURE TRANSMITTER 1PT-419	1PT-419	RH
PRESSURE TRANSMITTER 1PT-420	1PT-420	RH
1ARP1	1ARP1	S signal
1ARP2	1ARP2	S signal
1ARP3	1ARP3	S signal
1ARP4	1ARP4	S signal
1ASG1	1ASG1	S signal
1ASG2	1ASG2	S signal
1BRP1	1BRP1	S signal
1BRP2	1BRP2	S signal
1BRP3	1BRP3	S signal
1BRP4	1BRP4	S signal
1BSG1	1BSG1	S signal
1BSG2	1BSG2	S signal
1PLP	1PLP	S signal
1PT-429 -- PRESSURIZER PRESSURE TRANSMITTER	1PT-429	S signal
1PT-430 -- PRESSURIZER PRESSURE TRANSMITTER	1PT-430	S signal
1PT-431 -- PRESSURIZER PRESSURE TRANSMITTER	1PT-431	S signal
1PT-449 -- PRESSURIZER PRESSURE TRANSMITTER	1PT-449	S signal
1PT-945 -- CONTAINMENT PRESSURE TRANSMITTER	1PT-945	S signal
1PT-946 -- CONTAINMENT PRESSURE TRANSMITTER	1PT-946	S signal
1PT-947 -- CONTAINMENT PRESSURE TRANSMITTER	1PT-947	S signal
1PT-949 -- CONTAINMENT PRESSURE TRANSMITTER	1PT-949	S signal
1PT-950 -- CONTAINMENT PRESSURE TRANSMITTER	1PT-950	S signal
1 RWST	153-101	SI
11 SI ACCUMULATOR	101-011	SI
11 SI PUMP	11 SI PUMP	SI

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
12 SI ACCUMULATOR	101-012	SI
12 SI PUMP	12 SI PUMP	SI
1LT-920 -- 1 RWST LEVEL TRANSMITTER A	1LT-920	SI
1LT-921 -- 1 RWST LEVEL TRANSMITTER B	1LT-921	SI
CHECK VALVE SI-10-1 -- 11 SI PUMP DISCHARGE	SI-10-1	SI
CHECK VALVE SI-10-2 -- 12 SI PUMP DISCHARGE	SI-10-2	SI
CHECK VALVE SI-16-1 -- 11 SI PUMP DISCHARGE TO TEST	SI-6-1	SI
CHECK VALVE SI-16-2 -- 12 SI PUMP DISCHARGE TO TEST	SI-6-2	SI
CHECK VALVE SI-16-4 -- COLD LEG INJ LINE TO LOOP B COLD LEG	SI-16-4	SI
CHECK VALVE SI-16-5 -- COLD LEG INJ LINE TO LOOP A COLD LEG	SI-16-5	SI
CHECK VALVE SI-6-1 -- 12 ACCUMULATOR TO LOOP A CL	SI-6-1	SI
CHECK VALVE SI-6-2 -- 12 ACCUM TO LOOP A CL DWNSTM OF SI-6-1	SI-6-2	SI
CHECK VALVE SI-6-3 -- 11 ACCUMULATOR TO LOOP A CL	SI-6-3	SI
CHECK VALVE SI-6-4 -- 11 ACCUM TO LOOP A CL DWNSTM OF SI-6-3	SI-6-4	SI
CHECK VALVE SI-7-1 -- 1 RWST TO 11 RHR PUMP	SI-7-1	SI
CHECK VALVE SI-7-2 -- 1 RWST TO 12 RHR PUMP	SI-7-2	SI
CHECK VALVE SI-9-1 -- COLD LEG INJ LINE TO LOOP B COLD LEG	SI-9-1	SI
CHECK VALVE SI-9-2 -- COLD LEG INJ LINE TO LOOP A COLD LEG	SI-9-2	SI
CHECK VALVE SI-9-3 -- LOW HEAD SI TO TRN B RV NOZZLE	SI-9-3	SI
CHECK VALVE SI-9-4 -- LOW HEAD SI TO TRN A RV NOZZLE	SI-9-4	SI
CHECK VALVE SI-9-5 -- HI/LO HEAD SI TO B RV NOZZLE	SI-9-5	SI
CHECK VALVE SI-9-6 -- HI/LO HEAD SI TO A RV NOZZLE	SI-9-6	SI
MV-32067 -- 1 SI TO RX VESSEL TRN B	MV-32067	SI
MV-32069 -- 1 SI TO RX VESSEL TRN A	MV-32069	SI
MV-32070 -- 1 SI TO LOOP A COLD LEG	MV-32070	SI
MV-32071 -- 11 ACCUM TO LOOP A COLD LEG	MV-32071	SI
MV-32072 -- 12 ACCUM TO LOOP B COLD LEG	MV-32072	SI
MV-32075 -- SUMP B TO 11 RHR PUMP	MV-32075	SI
MV-32076 -- SUMP B TO 12 RHR PUMP	MV-32076	SI
MV-32077 -- SUMP B TO 11 RHR PUMP	MV-32077	SI
MV-32078 -- SUMP B TO 12 RHR PUMP	MV-32078	SI
MV-32079 -- 1 RWST TO SI PUMPS TRN A	MV-32079	SI
MV-32080 -- 1 RWST TO SI PUMPS TRN B	MV-32080	SI
MV-32081 -- 1 BAST TO SI PUMPS A	MV-32081	SI
MV-32082 -- 1 BAST TO SI PUMPS B	MV-32082	SI
MV-32162 -- 11 SI PUMP SUCTION	MV-32162	SI
MV-32163 -- 12 SI PUMP SUCTION	MV-32163	SI
MV-32202 -- 1 SI TEST LINE TO RWST TRN A	MV-32202	SI
MV-32203 -- 1 SI TEST LINE TO RWST TRN B	MV-32203	SI
MV-32206 -- 11 RHR TO 11 SI PUMP	MV-32206	SI
MV-32207 -- 12 RHR TO 12 SI PUMP	MV-32207	SI
RELIEF VALVE SI-25-1	SI-25-1	SI
RELIEF VALVE SI-25-2	SI-25-2	SI
11 BAST	153-041	VC
11 BORIC ACID TRANSFER PUMP	145-611	VC
11 CHARGING PUMP	145-041	VC
11 CHG PMP SPEED COMPUTER HI/LO PRESSURE SWITCH	1PSC-428A/B	VC
11 CHG PMP SPEED CONTROL LOC SV	SV-33687	VC
11 CHG PMP SPEED I/P CONVERTER	1LMS-428A	VC
11 CHG PMP SPEED MANUAL LOADER	1HSC-428D	VC

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
11 CHG PMP SPEED RNG EXP XMTR	1SPT-428A	VC
11 CHG PMP SPEED TRANSMITTER	1ST-428A	VC
11 SEAL WATER INJECTION FILTER	169-031	VC
11 SEAL WATER RETURN FILTER	169-061	VC
11 VOLUME CONTROL TANK	153-021	VC
12 CHARGING PUMP	145-042	VC
12 CHG PMP SPEED COMPUTER HI/LO PRESSURE SWITCH	1PSC-428C/D	VC
12 CHG PMP SPEED CONTROL LOC SV	SV-33689	VC
12 CHG PMP SPEED I/P CONVERTER	1LMS-428B	VC
12 CHG PMP SPEED MANUAL LOADER	1HSC-428E	VC
12 CHG PMP SPEED RNG EXP XMTR	1SPT-428B	VC
12 CHG PMP SPEED TRANSMITTER	1ST-428B	VC
12 SEAL WATER INJECTION FILTER	169-032	VC
12 SEAL WATER RETURN FILTER	169-062	VC
1AMR1	1AMR1	VC
1LT-106 -- 11 BAST LEVEL TRANSMITTER IV (Y)	1LT-106	VC
1LT-172 -- 11 BAST LEVEL TRANSMITTER II (W)	1LT-172	VC
1LT-190 -- 11 BAST LEVEL TRANSMITTER I (R)	1LT-190	VC
1LT-196 -- 11 BAST LEVEL TRANSMITTER III (B)	1LT-196	VC
CHECK VALVE VC-10-1 -- 11 CHG PUMP DISCHARGE	VC-10-1	VC
CHECK VALVE VC-10-2 -- 12 CHG PUMP DISCHARGE	VC-10-2	VC
CHECK VALVE VC-10-3 -- 13 CHG PUMP DISCHARGE	VC-10-3	VC
CHECK VALVE VC-13-3 -- BA FILTER TO BA BLENDER	VC-13-3	VC
CHECK VALVE VC-2-1 -- 11 VCT OUTLET	VC-2-1	VC
CHECK VALVE VC-2-2 -- 1 RWST TO CHG PUMP SUCTION	VC-2-2	VC
CHECK VALVE VC-8-15 -- BA FILTER TO EMERG BORATION	VC-8-15	VC
CHECK VALVE VC-8-4 -- 12 RCP SEAL INJECTION	VC-8-4	VC
CHECK VALVE VC-8-6 -- 12 RCP SEAL INJECTION	VC-8-6	VC
CHECK VALVE VC-8-7 -- 11 RCP SEAL INJECTION	VC-8-7	VC
CV-31198 -- CHARGING LINE TO 11 REGEN HX	CV-31198	VC
CV-31199 -- BA TO 11 BA BLENDER CONTROL VALVE	CV-31199	VC
CV-31200 -- 11 BA BLENDER TO CHG PUMPS SUCTION HEADER	CV-31200	VC
CV-31329 -- AUX SPRAY TO 11 PZR	CV-31329	VC
CV-31334 -- 11/12 RCP SEAL RETURN BYPASS CV	CV-31334	VC
CV-31335 -- 11 RCP SEAL WTR OUTLET ISOL CV	CV-31335	VC
CV-31336 -- 12 RCP SEAL WTR OUTLET ISOL CV	CV-31336	VC
LEVEL TRANSMITTER 1LT-112	1LT-112	VC
LEVEL TRANSMITTER 1LT-141	1LT-141	VC
MV-32060 -- 1 RWST TO CHARGING PUMP SUCTION	MV-32060	VC
MV-32166 -- 1 RCP SEAL RTN/EXCESS LETDOWN ISOL TRN A	MV-32166	VC
RELIEF VALVE VC-25-1	VC-25-1	VC
11 CONTAINMENT FAN COIL UNIT	174-011	ZC
12 CONTAINMENT FAN COIL UNIT	174-012	ZC
14 CONTAINMENT FAN COIL UNIT	174-014	ZC
DAMPER CD-34072 -- 11 FCU DISCH TO CNTMT DOME CD	CD-34072	ZC
DAMPER CD-34073 -- 11 FCU NORM DISCH TO GAP & STRUCT CD	CD-34073	ZC
DAMPER CD-34074 -- 12 FCU DISCH TO CNTMT DOME	CD-34074	ZC
DAMPER CD-34075 -- 12 FCU DISCH TO GAP & STRUCT CD	CD-34075	ZC
DAMPER CD-34076-- 13 FCU DISCH TO CNTMT DOME	CD-34076	ZC
DAMPER CD-34077 -- 13 FCU DISCH TO GAP & STRUCT CD	CD-34077	ZC

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
DAMPER CD-34078-- 14 FCU DISCH TO CNTMT DOME	CD-34078	ZC
DAMPER CD-34079 -- 14 FCU DISCH TO GAP & STRUCT CD	CD-34079	ZC
121 CONTROL ROOM AIR HANDLER	121 CR AH	ZH
121 CONTROL ROOM CHILLED WATER PUMP	045-591	ZH
122 CONTROL ROOM AIR HANDLER	122 CR AH	ZH
122 CONTROL ROOM CHILLED WATER PUMP	045-592	ZH
CHECK VALVE ZH-23-1	ZH-23-1	ZH
CHECK VALVE ZH-23-2	ZH-23-2	ZH
CV-31769 -- 121 CRM CHLR CONDENSER CL OUTLET TCV	CV-31769	ZH
CV-31785 -- 122 CRM CHLR CONDENSER CL OUTLET TCV	CV-31785	ZH
21 INVERTER	21 INVERTER	2AC 120
22 INVERTER	22 INVERTER	2AC 120
23 INVERTER	23 INVERTER	2AC 120
27 INVERTER	27 INVERTER	2AC 120
28 INVERTER	28 INVERTER	2AC 120
PANEL 211	PNL 211	2AC 120
PANEL 212	PNL 212	2AC 120
PANEL 213	PNL 213	2AC 120
PANEL 214	PNL 214	2AC 120
PANEL 227	PNL 227	2AC 120
PANEL 228	PNL 228	2AC 120
PANEL 234	PNL 234	2AC 230
PANEL 234, PHASE A XFRM	PNL 234/A XFMR	2AC 230
PANEL 234, PHASE B XFRM	PNL 234/B XFMR	2AC 230
PANEL 234, PHASE C XFRM	PNL 234/C XFMR	2AC 230
PANEL 235	PNL 235	2AC 230
PANEL 235, PHASE A XFRM	PNL 235/A XFMR	2AC 230
PANEL 235, PHASE B XFRM	PNL 235/B XFMR	2AC 230
PANEL 235, PHASE C XFRM	PNL 235/C XFMR	2AC 230
BUS 25 AUX RELAY CABINET		2AC 4160
BUS 25 LOAD SEQUENCE CABINET	BUS 25 CABINET	2AC 4160
BUS 26	BUS 26	2AC 4160
BUS 26 AUX RELAY CABINET		2AC 4160
BUS 26 LOAD SEQUENCE CABINET	BUS 26 CABINET	2AC 4160
BUS 27	BUS 27	2AC 4160
221 TRANSFORMER	221 XFMR	2AC 480
BUS 211 480V	BUS 211	2AC 480
BUS 212 480V	BUS 212	2AC 480
BUS 221 480V	BUS 221	2AC 480
BUS 222 480V	BUS 222	2AC 480
MCC 2A BUS 1	MCC 2A BUS 1	2AC 480
MCC 2A BUS 2	MCC 2A BUS 2	2AC 480
MCC 2AC BUS 1	MCC 2AC BUS 1	2AC 480
MCC 2AC BUS 2	MCC 2AC BUS 2	2AC 480
MCC 2K BUS 1	MCC 2K BUS 1	2AC 480
MCC 2KA BUS 2	MCC 2KA BUS 2	2AC 480
MCC 2L BUS 1	MCC 2L BUS 1	2AC 480
MCC 2L BUS 2	MCC 2L BUS 2	2AC 480
MCC 2LA1	MCC 2LA1	2AC 480
MCC 2TA1	MCC 2TA1	2AC 480

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
MCC 2TA2	MCC 2TA2	2AC 480
MCC 2X1	MCC 2X1	2AC 480
MCC 2X2	MCC 2X2	2AC 480
21 AF PUMP (MOTOR DRIVEN)	21 MD AFW PUMP	2AF
21 SG LEVEL TRANSMITTER 2LT-461	2LT-461	2AF
21 SG LEVEL TRANSMITTER 2LT-462	2LT-462	2AF
21 SG LEVEL TRANSMITTER 2LT-463	2LT-463	2AF
22 AF PUMP (TURBINE DRIVEN)	22 TD AFW PUMP	2AF
22 SG LEVEL TRANSMITTER 2LT-471	2LT-471	2AF
22 SG LEVEL TRANSMITTER 2LT-472	2LT-472	2AF
22 SG LEVEL TRANSMITTER 2LT-473	2LT-473	2AF
2ARP1	2ARP1	2AF
CHECK VALVE 2MS-15-1	2MS-15-1	2AF
CHECK VALVE 2MS-15-2	2MS-15-2	2AF
CHECK VALVE AF-14-5 -- CD TO 21 AF PUMP SUCTION	AF-14-5	2AF
CHECK VALVE AF-14-7 -- CD TO 22 AF PUMP SUCTION	AF-14-7	2AF
CHECK VALVE AF-15-11 -- 21 AF PUMP DISCHARGE	AF-15-11	2AF
CHECK VALVE AF-15-12 -- 22 AF PUMP DISCHARGE	AF-15-12	2AF
CHECK VALVE AF-15-5 -- 22 AF TO 22 SG	AF-15-5	2AF
CHECK VALVE AF-15-7 -- 22 AF TO 21 SG	AF-15-7	2AF
CHECK VALVE AF-16-3 -- AF TO 22 SG	AF-16-3	2AF
CHECK VALVE AF-16-4 -- AF TO 21 SG	AF-16-4	2AF
CV-31418 -- 21 MD AFW PUMP RECIRC/LUBE OIL CLNG VALVE	CV-31418	2AF
CV-31419 -- 22 TD AFW PUMP RECIRC/LUBE OIL CLNG VALVE	CV-31419	2AF
CV-31999 -- MS SUPPLY TO 22 AF PUMP	CV-31999	2AF
LIMIT SWITCH 33AC-31999 (on Valve)	33AC-31999	2AF
MANUAL VALVE 2AF-13-1 ON CROSS TIE BETWEEN 12 & 21 AF PUMPS	2AF-13-1	2AF
MV-32019 -- 21 SG STEAM TO 22 TD AFW PUMP	MV-32019	2AF
MV-32020 -- 22 SG STEAM TO 22 TD AFW PUMP	MV-32020	2AF
MV-32026 -- CL TO 21 MD AF PUMP SUCTION	MV-32026	2AF
MV-32030 -- CL TO 22 AFW PUMP SUCTION	MV-32030	2AF
MV-32246 -- 22 AF PMP DISCHRGE LN TO INLET OF 21 SG	MV-32246	2AF
MV-32247 -- 22 AF PMP DISCHRGE LN TO INLET OF 22 SG	MV-32247	2AF
MV-32336 -- CONDENSATE TO SUCTION OF 21 AF PUMP	MV-32336	2AF
MV-32345 -- CONDENSATE TO SUCTION OF 22 AF PUMP	MV-32345	2AF
MV-32383 -- LN 21 AF PMP DISCHRGE TO INLET OF 21 SG	MV-32383	2AF
MV-32384 -- LN 21 AF PMP DISCHRGE TO INLET OF 22 SG	MV-32384	2AF
PRESSURE SWITCH PS-17701 (22 AF PUMP DISCHARGE)	PS-17701	2AF
PRESSURE SWITCH PS-17705 (22 AF PUMP SUCTION)	PS-17705	2AF
PRESSURE SWITCH PS-17778 (21 AF PUMP DISCHARGE)	PS-17778	2AF
PRESSURE SWITCH PS-17779 (21 AF PUMP SUCTION)	PS-17779	2AF
SOLENOID VALVE SV-33300 (ON CV-31999)	SV-33300	2AF
21 CC HEAT EXCHANGER	21 CC HX	2CC
21 CC PUMP	245-121	2CC
22 CC HEAT EXCHANGER	22 CC HX	2CC
22 CC PUMP	245-122	2CC
CHECK VALVE 2CC-14-5 -- 21 RCP BEARING CC WATER RTN	2CC-14-5	2CC
CHECK VALVE 2CC-14-6 -- 22 RCP BEARING CC WATER RTN	2CC-14-6	2CC
CHECK VALVE 2CC-18-1 -- 22 RCP BEARING CC SUPPLY	2CC-18-1	2CC
CHECK VALVE 2CC-18-2 -- 21 RCP BEARING CC SUPPLY	2CC-18-2	2CC

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
CHECK VALVE 2CC-3-1 -- 21 CC PUMP DISCHARGE	2CC-3-1	2CC
CHECK VALVE 2CC-3-2 -- 22 CC PUMP DISCHARGE	2CC-3-2	2CC
CHECK VALVE 2CC-5-1 -- RETURN LINE TO 21 CC PUMP	2CC-5-1	2CC
CHECK VALVE 2CC-5-2 -- RETURN LINE TO 22 CC PUMP	2CC-5-2	2CC
CHECK VALVE 2CC-61-1 -- TR. B SUPPLY TO 21/22 RCP BRG CLG	2CC-61-1	2CC
CHECK VALVE 2CC-61-2 -- TR. A SUPPLY TO 21/22 RCP BRG CLG	2CC-61-2	2CC
CHECK VALVE 2CC-73-1 -- 21 RCP TBHX CC IN	2CC-73-1	2CC
CHECK VALVE 2CC-73-2 -- 22 RCP TBHX CC IN	2CC-73-2	2CC
MV-32128 -- 21 RHR HX CC INLET	MV-32128	2CC
MV-32129 -- 22 RHR HX CC INLET	MV-32129	2CC
MV-32211 -- CC SURGE TK. TO 21 CC PUMP	MV-32211	2CC
MV-32212 -- CC SURGE TK. TO 22 CC PUMP	MV-32212	2CC
MV-32268 -- TR. B CC SUPPLY TO 21/22 RCP	MV-32268	2CC
MV-32269 -- TR. A CC SUPPLY TO 21/22 RCP	MV-32269	2CC
21 CLG WTR. STRAINER	258-011	2CL
21 DIESEL COOLING SUPPLY FAN		2CL
22 CLG WTR. STRAINER	258-012	2CL
22 DIESEL CLG WATER PUMP AIR RECEIVERS A/B	246-011	2CL
22 DIESEL COOLING WATER PUMP CONTROL PANEL	70350	2CL
22 DSL CL PUMP FUEL OIL DAY TANK HIGH LEVEL SWITCH		2CL
22 FO DAY TANK (CL)	LA-16687	2CL
2CL-95-1 -- U2 CL PRESSURE REDUCING GOVERNOR VALVE	2CL-95-1	2CL
CHECK VALVE 2CL-12-1 -- 21 FCU CL INLET	2CL-12-1	2CL
CHECK VALVE 2CL-12-2 -- 23 FCU CL INLET	2CL-12-2	2CL
CHECK VALVE 2CL-12-3 -- 22 FCU CL INLET	2CL-12-3	2CL
CHECK VALVE 2CL-12-4 -- 24 FCU CL INLET	2CL-12-4	2CL
CHECK VALVE 2CL-43-2 -- 22 CL PUMP DISCHARGE	2CL-43-2	2CL
CV-39413 -- 22/24 FCU CL SUPPLY CONTROL VALVE	CV-39413	2CL
CV-39415 -- 21/23 FCU CL SUPPLY CONTROL VALVE	CV-39415	2CL
CV-39423 -- 21/23 FCU CL RETURN CONTROL VALVE	CV-39423	2CL
MV-32036 -- CL PUMP DISCHARGE HDR VALVE C	MV-32036	2CL
MV-32037 -- CL PUMP DISCHARGE HDR VALVE D	MV-32037	2CL
MV-32147 -- 21 FCU CL OUTLET ISOL A	MV-32147	2CL
MV-32148 -- 21 FCU CL OUTLET ISOL B	MV-32148	2CL
MV-32150 -- 22 FCU CL OUTLET ISOL A	MV-32150	2CL
MV-32151 -- 22 FCU CL OUTLET ISOLATION B	MV-32151	2CL
MV-32153 -- 23 FCU CL OUTLET ISOL A	MV-32153	2CL
MV-32154 -- 23 FCU CL OUTLET ISOL B	MV-32154	2CL
MV-32156 -- 24 FCU CL OUTLET ISOL A	MV-32156	2CL
MV-32157 -- 24 FCU CL OUTLET ISOLATION B	MV-32157	2CL
MV-32160 -- 21 CC HX COOLING WATER INLET	MV-32160	2CL
MV-32161 -- 22 CC HX COOLING WATER INLET	MV-32161	2CL
MV-32387 -- 22 FCU CL INLET	MV-32387	2CL
MV-32388 -- 23 FCU CL INLET	MV-32388	2CL
MV-32389 -- 24 FCU CL INLET	MV-32389	2CL
CHECK VALVE CS-46 -- 22 CS PUMP SUCTION LINE	CS-46	2CS
CHECK VALVE CS-47 -- 21 CS PUMP SUCTION LINE	CS-47	2CS
CHECK VALVE CS-48 -- 22 CS PUMP DISCHARGE TO SPRAY RINGS	CS-48	2CS
CHECK VALVE CS-49 -- 21 CS PUMP DISCHARGE TO SPRAY RINGS	CS-49	2CS
MV-32108 -- 21 CS PUMP SUCTION FROM 21 RHR HX	MV-32108	2CS

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
MV-32109 -- 22 CS PUMP SUCTION FROM 22 RHR HX	MV-32109	2CS
MV-32110 -- 21 CS PUMP SUCTION FROM 2 RWST	MV-32110	2CS
MV-32111 -- 22 CS PUMP SUCTION FROM 2 RWST	MV-32111	2CS
MV-32114 -- 21 CS PUMP DISCHARGE VALVE	MV-32114	2CS
MV-32116 -- 22 CS PUMP DISCHARGE VALVE	MV-32116	2CS
21 BATTERY CHARGER	21 BTTRY CHRGR	2DC
21 BATTERY DISCONNECT		2DC
22 BATTERY CHARGER	22 BTTRY CHRGR	2DC
22 BATTERY DISCONNECT		2DC
PANEL 21	PNL 21	2DC
PANEL 25	PNL 25	2DC
PANEL 251	PNL 251	2DC
PANEL 252	PNL 252	2DC
PANEL 253	PNL 253	2DC
PANEL 26	PNL 26	2DC
PANEL 261	PNL 261	2DC
PANEL 262	PNL 262	2DC
PANEL 263	PNL 263	2DC
PANEL 27	PNL 27	2DC
PANEL 28	PNL 28	2DC
21 D5 DIESEL GENERATOR BLDG. SUPPLY FAN	232-441	2DG
21 D5 DIESEL RM. RETURN AIR TEMP CONT.	2TC-5040	2DG
21 D5 DIESEL ROOM COOLING FAN	21 D5 COOL FAN	2DG
21 D5 DSL GEN BLDG RETURN FAN	232-451	2DG
21 D5 FUEL OIL DAY TANK LEVEL INDICATOR	2LI-5011B	2DG
21 D5 VERTICAL PANEL	21 D5 PANEL	2DG
22 D6 DIESEL GENERATOR BLDG. SUPPLY FAN	232-442	2DG
22 D6 DIESEL ROOM COOLING FAN	22 D6 COOL FAN	2DG
22 D6 DSL GEN BLDG RETURN FAN	232-452	2DG
22 D6 VERTICAL PANEL	22 D6 PANEL	2DG
23 D5 DG BLDG. SUPPLY FAN	232-443	2DG
23 D5 DSL GEN BLDG RETURN FAN	232-453	2DG
24 D6 DG BLDG SUPPLY FAN	232-444	2DG
24 D6 DSL GEN BLDG RETURN FAN	232-[illegible]4	2DG
D5 DIESEL GENERATOR	D5 DIESEL GEN	2DG
D5 DIESEL RM. RETURN AIR TEMP CONT.	2TY-5040	2DG
D5 ENG 1 COMBUSTION AIR FILTERS		2DG
D5 ENG 2 COMBUSTION AIR FILTERS		2DG
D5 ENG. 1 AUX. DESK PANEL		2DG
D5 ENG. 1 HT EXPANSION TANK	253-401	2DG
D5 ENG. 1 HT/LT RADIATORS	262-441	2DG
D5 ENG. 1 LT EXPANSION TANK	253-411	2DG
D5 ENG. 2 AUX. DESK PANEL		2DG
D5 ENG. 2 HT EXPANSION TANK	253-402	2DG
D5 ENG. 2 HT/LT RADIATORS	262-442	2DG
D5 ENG. 2 LT EXPANSION TANK	253-412	2DG
D5 ENGINE 1 RADIATOR FAN 1	D5 ENG 1 FAN 1	2DG
D5 ENGINE 1 RADIATOR FAN 2	D5 ENG 1 FAN 2	2DG
D5 ENGINE 2 RADIATOR FAN 1	D5 ENG 2 FAN 1	2DG
D5 ENGINE 2 RADIATOR FAN 2	D5 ENG 2 FAN 2	2DG

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
D5 FO DAY TANK	D5 DAY TANK	2DG
D5 FUEL OIL TRANSFER FILTERS		2DG
D5 INTAKE LOUVERS		2DG
D5 START AIR RECEIVERS 1A/1B	3681/1 & 3681/3	2DG
C5 START AIR RECEIVERS 2A/2B		2DG
D5 TEMP CONTROLLERS	2TE-5040	2DG
D5 TEMP CONTROLLERS	2TE-5558	2DG
D5 TEMP CONTROLLERS	2THL-5041	2DG
D5 TEMP CONTROLLERS	2TSL-5042	2DG
D6 DIESEL GENERATOR	D6 DIESEL GEN	2DG
D6 DIESEL RM. RETURN AIR TEMP CONTROL 1	2TC-6040	2DG
D6 DIESEL RM. RETURN AIR TEMP CONTROL 2	2TY-6040	2DG
D6 ENG 1 COMBUSTION AIR FILTERS		2DG
D6 ENG 2 COMBUSTION AIR FILTERS		2DG
D6 ENG. 1 AUX. DESK PANEL		2DG
D6 ENG. 1 HT EXPANSION TANK	253-403	2DG
D6 ENG. 1 HT/LT RADIATORS	262-443	2DG
D6 ENG. 1 LT EXPANSION TANK	253-413	2DG
D6 ENG. 2 AUX. DESK PANEL		2DG
D6 ENG. 2 HT EXPANSION TANK	253-404	2DG
D6 ENG. 2 HT/LT RADIATORS	262-444	2DG
D6 ENG. 2 LT EXPANSION TANK	253-414	2DG
D6 ENGINE 1 RADIATOR FAN 1	D6 ENG 1 FAN 1	2DG
D6 ENGINE 1 RADIATOR FAN 2	D6 ENG 1 FAN 2	2DG
D6 ENGINE 2 RADIATOR FAN 1	D6 ENG 2 FAN 2	2DG
D6 ENGINE 2 RADIATOR FAN 2	D6 ENG 2 FAN 2	2DG
D6 FO DAY TANK	6012	2DG
D6 FUEL OIL DAY TANK LEVEL INDICATOR		2DG
D6 FUEL OIL TRANSFER FILTERS		2DG
D6 INTAKE LOUVERS		2DG
D6 START AIR RECEIVERS 1A/1B		2DG
D6 START AIR RECEIVERS 2A/2B		2DG
D6 TEMP CONTROLLER 1	2THL-6041	2DG
D6 TEMP CONTROLLER 2	2TSL-6042	2DG
D6 TEMP CONTROLLER 3	2TE-6558	2DG
D6 TEMP CONTROLLER 4	2TE-6040	2DG
TB 2209 -- RELAY ROOM AUX RELAY CABINET	TB 2209	2ED
21 FUEL OIL STORAGE TANK	21 FO STG. TANK	2FO
21 FUEL OIL TRANSFER PUMP	245-881	2FO
22 FUEL OIL STORAGE TANK	22 FO STG. TANK	2FO
22 FUEL OIL TRANSFER PUMP	245-882	2FO
23 FUEL OIL STORAGE TANK	23 FO STG. TANK	2FO
23 FUEL OIL TRANSFER PUMP	245-883	2FO
24 FUEL OIL STORAGE TANK	24 FO STG. TANK	2FO
24 FUEL OIL TRANSFER PUMP	245-884	2FO
CHECK VALVE AT OUTLET OF 21 FOTP	21 OUTLET CV	2FO
CHECK VALVE AT OUTLET OF 22 FOTP	22 OUTLET CV	2FO
CHECK VALVE AT OUTLET OF 23 FOTP	23 OUTLET CV	2FO
CHECK VALVE AT OUTLET OF 24 FOTP	24 OUTLET CV	2FO
CV-31102 -- 21 SG PORV	CV-31102	2MS

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
CV-31107 -- 22 SG PORV	CV-31107	2MS
CV-31116 -- 21 SG MAIN STEAM ISOLATION VALVE	CV-31116	2MS
CV-31117 -- 22 SG MAIN STEAM ISOLATION VALVE	CV-31117	2MS
MN STM FR 21 STM GEN CHNNL I RED F XMTR	2FT-464	2MS
MN STM FR 21 STM GEN CHNNL II WHITE F XMTR	2FT-465	2MS
MN STM FR 22 STM GEN CHNNL III BLUE F XMTR	2FT-474	2MS
MN STM FR 22 STM GEN CHNNL IV YEL F XMTR	2FT-475	2MS
21 SI ACCUMULATOR	201-031	2RC
CV-31233 -- 2 PZR PORV B CONTROL VALVE	CV-31233	2RC
CV-31234 -- 2 PZR PORV A CONTROL VALVE	CV-31234	2RC
MV-32197 -- 2 PZR PORV A BLOCK VALVE	MV-32197	2RC
MV-32198 -- 2 PZR PORV B BLOCK VALVE	MV-32198	2RC
TRAIN B HOT SHUTDOWN PANEL	51500	2RC
21 RHR HT EXCHANGER	21 RHR HX	2RH
21 RHR PUMP	21 RHR PUMP	2RH
22 RHR HT EXCHANGER	22 RHR HX	2RH
22 RHR PUMP	22 RHR PUMP	2RH
CHECK VALVE 2RH-3-1 -- 22 RHR PUMP SUCTION LINE	2RH-3-1	2RH
CHECK VALVE 2RH-3-2 -- 21 RHR PUMP SUCTION LINE	2RH-3-2	2RH
CHECK VALVE 2RH-3-3 -- 22 RHR PUMP DISCHARGE LINE	2RH-3-3	2RH
CHECK VALVE 2RH-3-4 -- 21 RHR PUMP DISCHARGE LINE	2RH-3-4	2RH
CV-31238 -- 21 RHR HEAT EXCHANGER OUTLET CV	CV-31238	2RH
CV-31239 -- 22 RHR HEAT EXCHANGER OUTLET CV	CV-31239	2RH
MV-32167 -- 2 RHR TRN A TO RX VESSEL	MV-32167	2RH
MV-32168 -- 2 RHR TRN B TO RX VESSEL	MV-32168	2RH
MV-32169 -- 2 RHR RETURN TO LOOP B COLD LEG (SDC)	MV-32169	2RH
MV-32187 -- 2 RWST TO 21 RHR PUMP	MV-32187	2RH
MV-32188 -- 2 RWST TO 22 RHR PUMP	MV-32188	2RH
MV-32192 -- 2 LOOP A HOT LEG TO RHR TRN A	MV-32192	2RH
MV-32193 -- 2 LOOP A HOT LEG TO RHR TRN B	MV-32193	2RH
MV-32232 -- 2 LOOP B HOT LEG TO RHR TRN A	MV-32232	2RH
MV-32233 -- 2 LOOP B HOT LEG TO RHR TRN B	MV-32233	2RH
PRESSURE TRANSMITTER 2PT-419	2PT-419	2RH
PRESSURE TRANSMITTER 2PT-420	2PT-420	2RH
21PLP	21PLP	2S signal
2ARP2	2ARP2	2S signal
2ARP3	2ARP3	2S signal
2ARP4	2ARP4	2S signal
2ASG1	2ASG1	2S signal
2ASG2	2ASG2	2S signal
2BRP1	2BRP1	2S signal
2BRP2	2BRP2	2S signal
2BRP3	2BRP3	2S signal
2BRP4	2BRP4	2S signal
2BSG1	2BSG1	2S signal
2BSG2	2BSG2	2S signal
2PT-429 -- PRESSURIZER PRESSURE TRANSMITTER	2PT-429	2S signal
2PT-430 -- PRESSURIZER PRESSURE TRANSMITTER	2PT-430	2S signal
2PT-431 -- PRESSURIZER PRESSURE TRANSMITTER	2PT-431	2S signal
2PT-449 -- PRESSURIZER PRESSURE TRANSMITTER	2PT-449	2S signal

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
2PT-946 -- CONTAINMENT PRESSURE TRANSMITTER	2PT-946	2S signal
2PT-947 -- CONTAINMENT PRESSURE TRANSMITTER	2PT-947	2S signal
2PT-948 -- CONTAINMENT PRESSURE TRANSMITTER	2PT-948	2S signal
2PT-949 -- CONTAINMENT PRESSURE TRANSMITTER	2PT-949	2S signal
2PT-950 -- CONTAINMENT PRESSURE TRANSMITTER	2PT-950	2S signal
2 RWST	253-081	2SI
21 SI PUMP	245-071	2SI
22 SI ACCUMULATOR	201-032	2SI
22 SI PUMP	245-072	2SI
2LT-920 -- 2 RWST LEVEL TRANSMITTER A	2LT-920	2SI
2LT-921 -- 2 RWST LEVEL TRANSMITTER B	2LT-921	2SI
CHECK VALVE 2SI-10-1 -- 21 SI PUMP DISCHARGE	2SI-10-1	2SI
CHECK VALVE 2SI-10-2 -- 22 SI PUMP DISCHARGE	2SI-10-2	2SI
CHECK VALVE 2SI-16-1 -- 21 SI PUMP DISCHARGE TO TEST	2SI-6-1	2SI
CHECK VALVE 2SI-16-2 -- 22 SI PUMP DISCHARGE TO TEST	2SI-6-2	2SI
CHECK VALVE 2SI-16-4 -- COLD LEG INJ LINE TO LOOP B COLD LEG	2SI-16-4	2SI
CHECK VALVE 2SI-16-5 -- COLD LEG INJ LINE TO LOOP A COLD LEG	2SI-16-5	2SI
CHECK VALVE 2SI-6-1 -- 22 ACCUMULATOR TO LOOP A CL	2SI-6-1	2SI
CHECK VALVE 2SI-6-2 -- 22 ACCUM TO LOOP A CL DWNSTM OF 2SI-6-1	2SI-6-2	2SI
CHECK VALVE 2SI-6-3 -- 21 ACCUMULATOR TO LOOP A CL	2SI-6-3	2SI
CHECK VALVE 2SI-6-4 -- 21 ACCUM TO LOOP A CL DWNSTM OF 2SI-6-3	2SI-6-4	2SI
CHECK VALVE 2SI-7-1 -- 2 RWST TO 21 RHR PUMP	2SI-7-1	2SI
CHECK VALVE 2SI-7-2 -- 2 RWST TO 22 RHR PUMP	2SI-7-2	2SI
CHECK VALVE 2SI-9-1 -- COLD LEG INJ LINE TO LOOP B COLD LEG	2SI-9-1	2SI
CHECK VALVE 2SI-9-2 -- COLD LEG INJ LINE TO LOOP A COLD LEG	2SI-9-2	2SI
CHECK VALVE 2SI-9-3 -- LOW HEAD SI TO TRN B RV NOZZLE	2SI-9-3	2SI
CHECK VALVE 2SI-9-4 -- LOW HEAD SI TO TRN A RV NOZZLE	2SI-9-4	2SI
CHECK VALVE 2SI-9-5 -- HI/LO HEAD SI TO B RV NOZZLE	2SI-9-5	2SI
CHECK VALVE 2SI-9-6 -- HI/LO HEAD SI TO A RV NOZZLE	2SI-9-6	2SI
MV-32170 -- 2 SI TO RX VESSEL TRN B	MV-32170	2SI
MV-32172 -- 2 SI TO RX VESSEL TRN A	MV-32172	2SI
MV-32174 -- 21 ACCUM TO LOOP A COLD LEG	MV-32174	2SI
MV-32175 -- 22 ACCUM TO LOOP B COLD LEG	MV-32175	2SI
MV-32178 -- SUMP B TO 21 RHR PUMP	MV-32178	2SI
MV-32179 -- SUMP B TO 22 RHR PUMP	MV-32179	2SI
MV-32180 -- SUMP B TO 21 RHR PUMP	MV-32180	2SI
MV-32181 -- SUMP B TO 22 RHR PUMP	MV-32181	2SI
MV-32182 -- 2 RWST TO SI PUMPS TRN A	MV-32182	2SI
MV-32183 -- 2 RWST TO SI PUMPS TRN B	MV-32183	2SI
MV-32184 -- 2 BAST TO SI PUMPS MV A	MV-32184	2SI
MV-32185 -- 2 BAST TO SI PUMPS MV B	MV-32185	2SI
MV-32186 -- 2 BAST TO SI PUMPS MV C	MV-32186	2SI
MV-32190 -- 21 SI PUMP SUCTION	MV-32190	2SI
MV-32191 -- 22 SI PUMP SUCTION	MV-32191	2SI
MV-32204 -- 2 SI TEST LINE TO RWST TRN A	MV-32204	2SI
MV-32205 -- 2 SI TEST LINE TO RWST TRN B	MV-32205	2SI
MV-32208 -- 21 RHR TO 21 SI PUMP	MV-32208	2SI
MV-32209 -- 22 RHR TO 22 SI PUMP	MV-32209	2SI
RELIEF VALVE 2SI-25-1	2SI-25-1	2SI
RELIEF VALVE 2SI-25-2	2SI-25-2	2SI

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
21 BAST	253-041	2VC
21 CHARGING PUMP	245-041	2VC
21 CHARGING PUMP HI/LO PRESS. SWITCH	2PSC-428A/B	2VC
21 CHARGING PUMP MANUAL LOADER	2HSC-428E	2VC
21 CHARGING PUMP SPEED I/P CONVERTER	2LMS-428A	2VC
21 CHARGING PUMP SPEED RING EXP. XMTR	2SPT-428A	2VC
21 CHARGING PUMP SPEED TRANSMITTER	2ST-428A	2VC
21 CHG PMP SPEED CONTROL LOC SV	SV-33836	2VC
21 SEAL WATER INJECTION FILTER	269-031	2VC
21 SEAL WATER RETURN FILTER	269-061	2VC
21 VOLUME CONTROL TANK	253-021	2VC
22 CHARGING PUMP	245-042	2VC
22 CHARGING PUMP HI/LO PRESS. SWITCH	2PSC-428C/D	2VC
22 CHARGING PUMP MANUAL LOADER	2HSC-428D	2VC
22 CHARGING PUMP SPEED I/P CONVERTER	2LMS-428B	2VC
22 CHARGING PUMP SPEED RING EXP. XMTR	2SPT-428B	2VC
22 CHARGING PUMP SPEED TRANSMITTER	2ST-428B	2VC
22 CHG PMP SPEED CONTROL LOC SV	SV-33837	2VC
22 SEAL WATER INJECTION FILTER	269-032	2VC
22 SEAL WATER RETURN FILTER	269-062	2VC
2AMR1	2AMR1	2VC
2LT-106 -- 21 BAST LEVEL TRANSMITTER IV (Y)	2LT-106	2VC
2LT-172 -- 21 BAST LEVEL TRANSMITTER II (W)	2LT-172	2VC
2LT-190 -- 21 BAST LEVEL TRANSMITTER I (R)	2LT-190	2VC
2LT-196 -- 21 BAST LEVEL TRANSMITTER III (B)	2LT-196	2VC
CHECK VALVE 2VC-10-1 -- 21 CHG PUMP DISCHARGE	2VC-10-1	2VC
CHECK VALVE 2VC-10-2 -- 22 CHG PUMP DISCHARGE	2VC-10-2	2VC
CHECK VALVE 2VC-10-3 -- 23 CHG PUMP DISCHARGE	2VC-10-3	2VC
CHECK VALVE 2VC-13-3 -- BA FILTER TO BA BLENDER	2VC-13-3	2VC
CHECK VALVE 2VC-2-1 -- 21 VCT OUTLET	2VC-2-1	2VC
CHECK VALVE 2VC-2-2 -- 2 RWST TO CHG PUMP SUCTION	2VC-2-2	2VC
CHECK VALVE 2VC-8-15 -- BA FILTER TO EMERG BORATION	2VC-8-15	2VC
CHECK VALVE 2VC-8-4 -- 22 RCP SEAL INJECTION	2VC-8-4	2VC
CHECK VALVE 2VC-8-5 -- 21 RCP SEAL INJECTION	2VC-8-5	2VC
CHECK VALVE 2VC-8-6 -- 22 RCP SEAL INJECTION	2VC-8-6	2VC
CHECK VALVE 2VC-8-7 -- 21 RCP SEAL INJECTION	2VC-8-7	2VC
CV-31211 -- CHARGING LINE TO 21 REGEN HX	CV-31211	2VC
CV-31212 -- BA TO 21 BA BLENDER CONTROL VALVE	CV-31212	2VC
CV-31213 -- 21 BA BLENDER TO CHG PUMPS SUCTION HEADER	CV-31213	2VC
CV-31426 -- 21 RCP SEAL WTR OUTLET ISOL CV	CV-31426	2VC
CV-31427 -- 22 RCP SEAL WTR OUTLET ISOL CV	CV-31427	2VC
LEVEL TRANSMITTER 2LT-112	2LT-112	2VC
LEVEL TRANSMITTER 2LT-141	2LT-141	2VC
MV-32062 -- 2 RWST TO CHARGING PUMP SUCTION	MV-32062	2VC
MV-32189 -- 2 EMERGENCY BORATION TO CHG PUMP SUCTION	MV-32189	2VC
MV-32194 -- 2 RCP SEAL RTN/EXCESS LETDOWN ISOL TRN A	MV-32194	2VC
MV-32199 -- 1 RCP SEAL RTN/EXCESS LETDOWN ISOL TRN B	MV-32199	2VC
MV-32210 -- 2 RCP SEAL RTN/EXCESS LETDOWN ISOL TRN B	MV-32210	2VC
21 CONTAINMENT FAN COIL UNIT	274-011	2ZC
22 CONTAINMENT FAN COIL UNIT	274-012	2ZC

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
23 CONTAINMENT FAN COIL UNIT	274-013	2ZC
24 CONTAINMENT FAN COIL UNIT	274-014	2ZC
DAMPER CD-34080 -- 21 FCU DISCH TO CNTMT DOME CD	CD-34080	2ZC
DAMPER CD-34081 -- 21 FCU NORM DISCH TO GAP & STRUCT CD	CD-34081	2ZC
DAMPER CD-34082 -- 22 FCU DISCH TO CNTMT DOME	CD-34082	2ZC
DAMPER CD-34083 -- 22 FCU DISCH TO GAP & STRUCT CD	CD-34083	2ZC
DAMPER CD-34084-- 23 FCU DISCH TO CNTMT DOME	CD-34084	2ZC
DAMPER CD-34085 -- 23 FCU DISCH TO GAP & STRUCT CD	CD-34085	2ZC
DAMPER CD-34086-- 24 FCU DISCH TO CNTMT DOME	CD-34086	2ZC
DAMPER CD-34087 -- 24 FCU DISCH TO GAP & STRUCT CD	CD-34087	2ZC
CV-31247	CV-31247	
CV-31248	CV-31248	
CV-31252 -- CC FROM LETDOWN HX ISOLATION VALVE, PENETRATION 40	CV-31252	
CV-31253 -- CC FROM LETDOWN HX ISOLATION VALVE, PENETRATION 40	CV-31253	
CV-31321 -- REACTOR MAKEUP TO PRT ISOLATION VALVE, PENETRATION 45	CV-31321	
CV-31325 -- LETDOWN LINE ISOLATION VALVE, PENETRATION 11	CV-31325	
CV-31326 -- LETDOWN LINE ISOLATION VALVE, PENETRATION 11	CV-31326	
CV-31327 -- LETDOWN LINE ISOLATION VALVE, PENETRATION 11	CV-31327	
CV-31339 -- LETDOWN LINE ISOLATION VALVE, PENETRATION 11	CV-31339	
CV-31342 -- REACTOR MAKEUP TO PRT ISOLATION VALVE, PENETRATION 45	CV-31342	
CV-31347 -- LETDOWN LINE ISOLATION VALVE, PENETRATION 11	CV-31347	
CV-31348 -- LETDOWN LINE ISOLATION VALVE, PENETRATION 11	CV-31348	
CV-31349 -- LETDOWN LINE ISOLATION VALVE, PENETRATION 11	CV-31349	
CV-31430 -- LETDOWN LINE ISOLATION VALVE, PENETRATION 11	CV-31430	
CV-31436 -- RCDT PUMP DISCHARGE ISOLATION VALVE, PENETRATION 5	CV-31436	
CV-31437 -- RCDT PUMP DISCHARGE ISOLATION VALVE, PENETRATION 5	CV-31437	
CV-31438 -- CONTAINMENT SUMP A ISOLATION VALVE, PENETRATION 26	CV-31438	
CV-31439 -- CONTAINMENT SUMP A ISOLATION VALVE, PENETRATION 26	CV-31439	
CV-31619 -- CONTAINMENT SUMP C ISOLATION VALVE, PENETRATION 26	CV-31619	
CV-31620 -- CONTAINMENT SUMP C ISOLATION VALVE, PENETRATION 26	CV-31620	
CV-31621 -- VACUUM BREAKER ISOLATION VALVE, PENETRATION 41A	CV-31621	
CV-31622 -- VACUUM BREAKER ISOLATION VALVE, PENETRATION 41B	CV-31622	
CV-31625 -- VACUUM BREAKER ISOLATION VALVE, PENETRATION 41A	CV-31625	
CV-31626 -- VACUUM BREAKER ISOLATION VALVE, PENETRATION 41B	CV-31626	
CV-31627 -- VACUUM BREAKER ISOLATION VALVE, PENETRATION 41A	CV-31627	
CV-31628 -- VACUUM BREAKER ISOLATION VALVE, PENETRATION 41B	CV-31627	
CV-31630 -- VACUUM BREAKER ISOLATION VALVE, PENETRATION 41A	CV-31630	
CV-31631 -- VACUUM BREAKER ISOLATION VALVE, PENETRATION 41B	CV-31631	
CV-31735 -- RCDT PUMP DISCHARGE ISOLATION VALVE, PENETRATION 5	CV-31735	
CV-31736 -- RCDT PUMP DISCHARGE ISOLATION VALVE, PENETRATION 5	CV-31736	
CV-31740 -- INSTRUMENT AIR ISOLATION VALVE, PENETRATION 20	CV-31740	
CV-31741 -- INSTRUMENT AIR ISOLATION VALVE, PENETRATION 20	CV-31741	
CV-31742 -- INSTRUMENT AIR ISOLATION VALVE, PENETRATION 20	CV-31742	
CV-31743 -- INSTRUMENT AIR ISOLATION VALVE, PENETRATION 20	CV-31743	
CV-31920 -- SUPPLY AIR VENT ISOLATION VALVE, PENETRATION 42A	CV-31920	
CV-31923 -- SUPPLY AIR VENT ISOLATION VALVE, PENETRATION 50	CV-31923	
CV-31925 -- SUPPLY AIR VENT ISOLATION VALVE, PENETRATION 50	CV-31925	
CV-31926 -- SUPPLY AIR VENT ISOLATION VALVE, PENETRATION 42A	CV-31926	
CV-31927 -- SUPPLY AIR VENT ISOLATION VALVE, PENETRATION 42A	CV-31927	
CV-31928 -- SUPPLY AIR VENT ISOLATION VALVE, PENETRATION 50	CV-31928	

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
CV-31929 -- SUPPLY AIR VENT ISOLATION VALVE, PENETRATION 42A	CV-31929	
CV-31930 -- SUPPLY AIR VENT ISOLATION VALVE, PENETRATION 50	CV-31930	
MV-32023 -- FEEDWATER ISOLATION VALVE, PENETRATION 7A	MV-32023	
MV-32024 -- FEEDWATER ISOLATION VALVE, PENETRATION 7B	MV-32024	
MV-32028 -- FEEDWATER ISOLATION VALVE, PENETRATION 7C	MV-32028	
MV-32031, CL ISOLATION VALVE	MV-32031	
MV-32033, CC ISOLATION VALVE	MV-32120	
MV-32040 -- STEAM GENERATOR BLOWDOWN ISOLATION VALVE, PENETRATION 8A	MV-32040	
MV-32043 -- STEAM GENERATOR BLOWDOWN ISOLATION VALVE, PENETRATION 8A	MV-32043	
MV-32044 -- STEAM GENERATOR BLOWDOWN ISOLATION VALVE, PENETRATION 8B	MV-32044	
MV-32048 -- STEAM GENERATOR BLOWDOWN ISOLATION VALVE, PENETRATION 8C	MV-32048	
MV-32049 -- STEAM GENERATOR BLOWDOWN ISOLATION VALVE, PENETRATION 8D	MV-32049	
MV-32051 -- STEAM GENERATOR BLOWDOWN ISOLATION VALVE, PENETRATION 8C	MV-32051	
MV-32058 -- STEAM GENERATOR BLOWDOWN ISOLATION VALVE, PENETRATION 8B	MV-32058	
MV-32059 -- STEAM GENERATOR BLOWDOWN ISOLATION VALVE, PENETRATION 8D	MV-32059	
MV-32089 -- CC TO RCP 11 ISOLATION VALVE, PENETRATION 32A	MV-32089	
MV-32090 -- CC FROM RCP 11 ISOLATION VALVE, PENETRATION 33A	MV-32090	
MV-32091 -- CC TO RCP 12 ISOLATION VALVE, PENETRATION 32B	MV-32091	
MV-32092 -- CC FROM RCP 12 ISOLATION VALVE, PENETRATION 33B	MV-32092	
MV-32095 -- CC TO EXCESS LETDOWN HX, PENETRATION 39	MV-32095	
MV-32115, CC ISOLATION VALVE	MV-32115	
MV-32120, CC ISOLATION VALVE	MV-32120	
MV-32121, CC ISOLATION VALVE	MV-32121	
MV-32122, CC ISOLATION VALVE	MV-32122	
MV-32123, CC ISOLATION VALVE	MV-32123	
MV-32124 -- CC TO RCP 21 ISOLATION VALVE, PENETRATION 32A	MV-32124	
MV-32125 -- CC FROM RCP 21 ISOLATION VALVE, PENETRATION 33A	MV-32125	
MV-32126 -- CC TO RCP 22 ISOLATION VALVE, PENETRATION 32B	MV-32126	
MV-32127 -- CC FROM RCP 22 ISOLATION VALVE, PENETRATION 33B	MV-32127	
MV-32130 -- CC TO EXCESS LETDOWN HX, PENETRATION 39	MV-32130	
MV-32176 -- COLD LEG SAFETY INJECTION ISOLATION VALVE, PENETRATION 28B	MV-32176	
MV-32177 -- REACTOR VESSEL SAFETY INJECTION ISOLATION VALVE, PENETRATION 28A	MV-32177	
MV-32234 -- LETDOWN LINE ISOLATION VALVE, PENETRATION 11	MV-32234	
MV-32235 -- LETDOWN LINE ISOLATION VALVE, PENETRATION 11	MV-32235	
MV-32242 -- AUXILIARY FEEDWATER ISOLATION VALVE, PENETRATION 46B	MV-32242	
MV-32243 -- AUXILIARY FEEDWATER ISOLATION VALVE, PENETRATION 46A	MV-32243	
MV-32248 -- AUXILIARY FEEDWATER ISOLATION VALVE, PENETRATION 46D	MV-32248	
MV-32249 -- AUXILIARY FEEDWATER ISOLATION VALVE, PENETRATION 46C	MV-32249	
MV-32271 -- SUPPLY AIR VENT ISOLATION VALVE, PENETRATION 50	MV-32271	
MV-32273 -- SUPPLY AIR VENT ISOLATION VALVE, PENETRATION 42A	MV-32273	
MV-32274 -- POST LOCA H2 CONTROL AIR ISOLATION VALVE, PENETRATION 50	MV-32274	
MV-32276 -- POST LOCA H2 CONTROL AIR ISOLATION VALVE, PENETRATION 42A	MV-32276	
MV-32290 -- SUPPLY AIR VENT ISOLATION VALVE, PENETRATION 42A	MV-32290	
MV-32292 -- SUPPLY AIR VENT ISOLATION VALVE, PENETRATION 42A	MV-32292	
MV-32293 -- POST LOCA H2 CONTROL AIR ISOLATION VALVE, PENETRATION 42a	MV-32293	
MV-32295 -- POST LOCA H2 CONTROL AIR ISOLATION VALVE, PENETRATION 50	MV-32295	
NSSS COMPONENTS AND PIPING		
CATEGORY 1 STRUCTURES		
CATEGORY 2 STRUCTURES		
CONCRETE BLOCK WALLS		

Table A.2.3-1, continued
Seismically Rugged Components

COMPONENT	IDNO	SYSTEM
HVAC DUCTING		
CABLE TRAYS & CONDUIT		
PIPING		
U1 CONTAINMENT PENETRATIONS		
U2 CONTAINMENT PENETRATIONS		

Table A.2.3-2 Relays Outside the SQUG Program Scope

Relay ID	Equipment Affected	Manu./ Model No.	Description
71A1	11 BAST Lo Level	West. BFD-11S	Relays control valve opening signal to MV-32079 and MV-32080 that effects alignment of SI suction source to the RWST.
1-71A1X	11 BAST Lo Level	West. BFD-44S	
71A2	11 BAST Lo Level	West. BFD-11S	
1-71A2X	11 BAST Lo Level	West. BFD-44S	
71B1	11 BAST Lo Level	West. BFD-11S	
71B1X	11 BAST Lo Level	West. BFD-44S	
71B2	11 BAST Lo Level	West. BFD-11S	
71B2X	11 BAST Lo Level	West. BFD-44S	
1-LC106C-XA	BAST/RWST Auto-Transfer	West. BF-42F	Relays are tied to level-sensing circuit on BAST that effect auto-transfer of SI suction source from BAST to RWST.
1-LC106C-XB	BAST/RWST Auto-Transfer	West. BF-42F	
1-LC172C-XA	BAST/RWST Auto-Transfer	West. BF-42F	
1-LC172C-XB	BAST/RWST Auto-Transfer	West. BF-42F	
1-LC190C-XA	BAST/RWST Auto-Transfer	West. BF-42F	
1-LC190C-XB	BAST/RWST Auto-Transfer	West. BF-42F	
1-LC196C-XA	BAST/RWST Auto-Transfer	West. BF-22F	
1-LC196C-XB	BAST/RWST Auto-Transfer	West. BF-22F	
1-PC628XB	MV-32207	West. BF-42F	Relays effect opening of the SI suction supply from RHR on SI High Head Recirc.
1-PC629XA	MV-32206		

Table A.2.3-2, continued
Relays Outside the SQUG Program Scope

Relay ID	Equipment Affected	Manu./ Model No.	Description
62/16-1	12 AF Pump Trips	Agastat 7012PD	Relays trip pumps off-line on failure of CST supply to avoid pump damage. After operator action to realign to alternate cooling water supply, pumps are manually restarted.
62/2	22 AF Pump Trips	Agastat 7012PC	
62/2	11 AF Pump Trips	Agastat 7012PC	
SI-11X	11 SI Pump	West. BFD-84S	Pump control circuit
SI-13X	MV-32081		Valve control circuit (suction path to BAST)

A.2.4 Results

Components that were not screened from further review out by the walkdowns (Section A.2.2) or the screening evaluations are listed in Table A.2.4-1. Most of these will be addressed by the SQUG program or their failures were shown by systems analysis to be of no consequence. The remaining components are outliers which require resolution. These outlier components consist of electrical equipment with potential seismic interactions which could cause impact-induced relay chatter.

A.2.4.1 Disposition of Components Needing Additional Evaluation

After Supplement 5 to Generic Letter 88-20 was issued, NSP elected to complete the seismic IPEEE for Prairie Island with an evaluation equivalent to a reduced scope seismic margins assessment with an additional focus on certain key components. Following the guidance of NUREG-1407 [14], outliers for reduced scope plants should be evaluated by the provisions of the Generic Implementation Procedures (GIP) [15] if the plant is also in the SQUG program. The Prairie Island SQUG program has submitted their evaluation and conclusions [20], which have been considered in the discussion below. Structures and components outside of the SQUG program scope that could not be screened following the GIP should be evaluated following the requirements of the plant USAR.

The following two sections provide a summary of the SQUG outliers that pertain to the IPEEE scope, and the items addressed through systems analysis. No unscreened components or structures were identified that required evaluation to USAR requirements. The disposition of the components in Table A.2.4-1 using these reduced scope seismic margin assessment criteria is discussed here.

A.2.4.1.1 Disposition Based on SQUG Program Results

Containment Fan Coil Unit Cooling Water Control Valves CV-39401 and CV-39409: A potentially adverse interaction between the control valves and nearby conduit was identified during the IPEEE walkdown in the Auxiliary Building. This potential interaction was also noted by SQUG. SQUG has designated these valves as outliers so that resolution of the potential interaction will be resolved through the closure of USI A-46 at Prairie Island.

Containment Fan Coil Unit 13: SQUG has flagged this FCU as an outlier because the floor response spectra (demand) at the location of this equipment exceeds the allowable capacity. The IPEEE walkdown also identified a potential anchorage issue for this FCU. IPEEE will credit resolution of this issue in the closure of the A-46 Program.

Batteries 11 and 21: Issues regarding the ruggedness of the batteries and their anchorage were raised by both IPEEE and SQUG. SQUG has identified these batteries as outliers,

requiring them to be addressed as part of the closure to the A-46 program at Prairie Island.

Batteries 12 and 22: Both the IPEEE and SQUG walkdowns identified missing spacers in the battery restraint configuration. SQUG has designated the batteries as outliers. Ensuring adequate support of the battery will be addressed as part of the closure of the Prairie Island A-46 Program.

Battery Charger 11, 12, and 22: Anchorage issues were raised by both IPEEE and SQUG related to the cabinet bases. SQUG has also raised a question about a potentially adverse seismic interaction for Battery Charger 22. These Battery Chargers have been added to the list of A-46 Program outliers and will be addressed through the closure of the SQUG effort.

Gage Panels for D1 and D2: These panels are located on the diesel skids. The issue raised by both IPEEE and SQUG has to do with the vibration isolators used at the base of the panels. These isolators were described by SQUG as "flexible (wobbly) steel springs." Both Gage Panels have been flagged as outliers by SQUG and will be addressed by the actions to close the A-46 Program.

125VDC Panels 11, 12, and 22: The distribution panels are mounted to the floor. The walkdown identified that the load bearing point at the panel base is elevated above the floor level, giving rise to potentially unacceptable bending stresses. SQUG identified this configuration as potentially unacceptable and has designated these panels as outliers that must be addressed by the actions to close the A-46 Program.

11, 21 Screenhouse Roof Exhaust Fans: SQUG determined that the seismic demand on the Exhaust Fan anchorage potentially exceeds the seismic capacity. The IPEEE identified similar concerns during the walkdown. Anchorage details for the fan will be reviewed and confirmed to be adequate or corrected as part of the closure of the A-46 Program.

Diesel-Driven Cooling Water Pumps 12 and 22 Jacket Heat Exchangers: The horizontally-oriented heat exchangers were identified as having questionable attachment capacity by both SQUG and IPEEE. These items were designated as outliers by SQUG because the heat exchangers are "not secured to the pedestals (mounting cradles are secured to the pedestals but heat exchanger is not attached to the cradles. Further, both cradles have slotted mounting holes)." These components will be addressed through resolution of outliers in the closure of the Prairie Island A-46 Program.

Diesel-Driven Cooling Water Pumps 12 and 22: SQUG and IPEEE have raised issues with both the anchorage and the shaft length for these pumps. SQUG has identified these pumps as outliers requiring resolution under the closure of the A-46 Program.

Motor Control Centers (MCCs) 1K1, 1L2, 2K2, 1AB1, 1AB2, 2LA2, 1TA1, and 1TA2: These MCCs have issues involving anchorage inadequacies or adverse seismic-induced interactions raised by both SQUG and IPEEE. Those MCCs having anchorage issues involve the cabinet being supported off the floor by inverted base channels which are then bolted to the floor by anchors which pass through these base channels, creating potentially unacceptable bending stresses. Issues of potential interaction involve possible contact with nearby equipment during the seismic event. SQUG has flagged these MCCs as outliers that must be addressed as part of the closure of the A-46 Program.

CL (121 and 122) and DG (121 and 123) Oil Storage Tanks: SQUG has identified these tanks as outliers because the flexibility of associated buried piping could not be determined from available documentation. The IPEEE, faced with the same concern, will credit the resolution of this issue in the closure of the A-46 Program.

Pressurizer Relief Valves 1RC-10-1 and 2, 2RC-10-1 and 2: These valves were not evaluated for seismic adequacy within the IPEEE because their function is not credited. These valves have been identified as outliers with the A-46 Program and will be addressed further as part of the closure of that program.

North (121, 122) and South (121, 122) Unit Coolers: These have been identified within the Prairie Island A-46 Program as being SQUG outliers and, therefore, were not evaluated further in the IPEEE seismic effort. The IPEEE will credit resolution of the SQUG issues established with the closure of that program.

Control Room Water Chillers (121, 122): These have been identified within the Prairie Island A-46 Program as being SQUG outliers and, therefore, were not evaluated further in the IPEEE seismic evaluation effort. The IPEEE will credit resolution of the SQUG issues established with the closure of that program.

Control Room Ceiling: Aluminum diffusers rest on T-bar runners, above which the ceiling lights are located. Walkdowns by IPEEE and SQUG noted the potential for the diffusers to fall as a result of a seismic event, thereby creating a personnel hazard, in addition to adverse interactions with control room panels and racks. SQUG has listed the control room ceiling as an outlier issue. The adequacy of the diffuser support design will be resolved as part of the closure of the A-46 Program at Prairie Island.

A.2.4.1.2 Disposition Based on Systems Analysis

Equipment in Support of Room Cooling Functions: Seismic walkdowns performed under the IPEEE have identified various components with questionable anchorage or ruggedness which may not withstand a seismic event. Instead of performing seismic analyses of these components, credit has been taken for analyses previously performed by NSP that considered whether the room cooling functions supported by these components are critical. The affected equipment is discussed below:

Panels 132 and 133: Failure of these panels affects room cooling to the Unit 1 4kV safegard bus rooms. Conservative room heat-up analyses have been performed that conclude the room cooling function is not critical. The analysis for the 4kV bus rooms [26] shows that the only affected components in these rooms are the load sequencers. However, the seismic event is postulated to cause a loss of offsite power, which in turn will require starting the emergency diesels. This will require the functioning of the load sequencers almost immediately. Therefore, by the time the rooms heat up to the temperature at which the operability of the sequencers become questionable, their function will have already been completed.

RHR Pit Cooling (11, 12, 21, and 22 Unit Coolers): Analysis performed by NSP [28] shows that long term post-LOCA RHR pit temperatures reach only 140 F with both trains of RHR in recirculation and no ventilation available. This is well within the range needed for pump operability during the required mission time. The unit coolers are required for Technical Specification operability of the pumps only to preserve the EQ margin for operation up to one year following a postulated accident.

SWGR / Bus Rooms (15, 16) Unit Coolers: See discussion above for Panels 132 and 133 and how it applies to the 4kV SWGR/bus rooms.

D5/D6 480V Aux. Air Handlers (21/22) and 480V SWGR Room Aux. Condensing Units (21/22): These components provide normal air circulation/conditioning. These components are not needed to respond to, or mitigate, accident conditions. Loss of any or all of these components would not lead to adverse environmental conditions affecting critical components.

<u>Containment Spray Pumps (11, 12, 21, 22)</u>: No credit was taken for the containment environment control function provided by the Containment Spray system. Containment Spray is not required to limit containment pressure following a small LOCA. Rather, its principal purpose in the IPEEE would be for long term decay heat removal. However, containment air cooling can be provided through the Fan Coil Units (FCUs). There are four FCUs in each containment, with a design capacity that requires only 2 of 4 to be operable to ensure sufficient cooling occurs. Accordingly, the Containment Spray pumps were excluded from further consideration in the seismic ruggedness evaluation within the IPEEE.

<u>Steam Generator Level Logic Relays and Bistables</u>: The IPEEE walkdown identified potential anchorage concerns with the panels containing these components. The purpose of these components in the Steam Generator Level Logic circuitry is to trigger initiation of the Auxiliary Feedwater (AFW) pumps when normal makeup becomes inadequate. The components in question include the following:

11 Steam Generator Logic Relay 1LC-463C-XA
11 Steam Generator Logic Relay 1LC-461B-XA
11 Steam Generator Logic Relay 1LC-462A-XA
12 Steam Generator Logic Relay 1LC-473C-XA
12 Steam Generator Logic Relay 1LC-473C-XB
21 Steam Generator Logic Relay 2LC-463C-XA
21 Steam Generator Logic Relay 2LC-461B-XA
21 Steam Generator Logic Relay 2LC-462A-XA
22 Steam Generator Logic Relay 2LC-473C-XA
22 Steam Generator Logic Relay 2LC-473C-XB
11 Steam Generator Bistable 1LC-461B-XA/XB
11 Steam Generator Bistable 1LC-462A-XA/XB
11 Steam Generator Bistable 1LC-463C-XA/XB
12 Steam Generator Bistable 1LC-472A-XA/XB
12 Steam Generator Bistable 1LC-473C-XA/XB
21 Steam Generator Bistable 2LC-461B-XA/XB
21 Steam Generator Bistable 2LC-462A-XA/XB
21 Steam Generator Bistable 2LC-463C-XA/XB
22 Steam Generator Bistable 2LC-472A-XA/XB
22 Steam Generator Bistable 2LC-473C-XA/XB

In the postulated seismic event, a loss of offsite power (LOOP) occurs which causes a loss of normal feedwater (Main Feedwater pump trip). The loss of power is sensed by plant equipment (e.g., undervoltage relays) which then auto-initiates the turbine driven AFW pump. The relays and bistables are not needed, therefore, in response to the LOOP.

<u>Turbine-Driven AFW Pump Trip and Throttle Valves (CV-31059 and CV-31060)</u>: The IPEEE walkdown identified a seismic stability concern for these valves. The concern is whether a seismic event would cause the valves to trip closed, thereby disabling their respective turbine-driven AFW pumps. The seismic concern does not involve a failure of the valve itself, rather of the trip mechanism for the valve. An operator action is defined in existing procedures to restore the trip and throttle valve in the event the valve trips for any reason. However, the operator action involves going to the Auxiliary Feedwater pump room, where the valve is located, and performing the restoration locally. The IPEEE seismic walkdown traced the path from the control room to the valve location and concluded that there are no potential obstructions that could occur due to the earthquake that would prevent the operators from reaching the valve and completing the restoration activity. Based on this, credit is taken for the availability of these valves and the turbine-driven AFW pumps in both units.

Air Compressors for Diesel Cooling Water Pumps (12 and 22): The air compressors are needed to charge the air receivers on the Emergency Diesel Generators for starting. As a result of the seismic event, it is assumed that these compressors are unavailable. This is of no consequence since the air receivers have sufficient capacity to support starting the diesels upon demand.

Diesel Generator Fuel Oil Storage Tanks (122 and 124): The IPEEE seismic walkdown raised a concern about these tanks regarding the flexibility of buried pipe. However, Tanks 121 and 123 have been determined by SQUG to be acceptable to SSE levels. In addition to the 1-2 hour fuel supply available in the day tanks, fuel from the interconnected storage tanks can supply any single diesel for up to two weeks. Therefore, the capacity within Tanks 121 and 123 is considered sufficient to meet the needs for the postulated post-earthquake plant conditions assuming the tanks have been dispositioned by SQUG. Tanks 122 and 124 are not credited and no further seismic evaluation is required.

Steam Generator (11, 12, 21, 22) PORV Accumulator: Anchorage concerns were raised for these components during the IPEEE walkdowns. The accumulators provide a source of pressurized air that enable operation of the relief valves on the steam generators. The relief valves provide a means to depressurize the steam generator to perform secondary side cooldown. The PORVs fail closed on loss of instrument air. Since instrument air is assumed to be lost due to the seismic event, no credit is taken for the PORVs, although they would have a limited number of cycles available with the charge stored in the accumulators.

Boric Acid Transfer Pumps (11, 12, 21, 22): The IPEEE seismic walkdown identified potential anchorage concerns associated with these pumps. The pumps supply boric acid from the batch processing tanks to the three Boric Acid Storage Tanks. One of these boric acid tanks provides supply for SI injection in the event of a loss of primary coolant. A sufficient supply of borated water is already available from the Boric Acid Storage Tank (BAST) and the Refueling Water Storage tank (RWST) without having to rely on the backup supply capabilities using the Boric Acid Transfer Pumps.

Charging Pumps (13, 23): Anchorage concerns related to these pumps were raised by the IPEEE during the seismic walkdowns. There are three charging pumps that take suction from the Volume Control Tank, with the RWST providing a backup supply, to provide reactor coolant makeup and reactor coolant pump seal water injection cooling. In the seismic-induced accident scenario postulated here, makeup is provided by SI through injection and then recirculation. Seal injection cooling is critical to prevent a small LOCA occurring through failed reactor coolant pump seals. One charging pump is needed for this function; two have been determined through the USI A-46 effort to be seismically rugged (Pumps 11 and 12 in unit 1; Pumps 21 and 22 in Unit 2). The third

pump in each unit was not looked at by SQUG. Because of the redundancy already available through the two charging pumps, not to mention the alternate cooling path available through Component Cooling Water to the RCP thermal barrier, the third charging pump is considered unnecessary and requires no further evaluation under the seismic IPEEE.

Buses 11, 12, 13, and 14: The IPEEE seismic walkdown noted these bus panels as potentially having inadequate anchorage. These buses support Main Feedwater, RCPs and Condensate, which are lost as a result of the loss of offsite power. Since emergency buses do not support these components, they require no further evaluation under the seismic IPEEE.

MCCs 1M1, 1M 2, 1MA1, 1MA2: Anchorage issues were raised for these MCCs during the IPEEE walkdown. These MCCs support Auxiliary Building Ventilation. This function is not modeled in the PRA, nor are these components included in the database of PRA basic events. Cooling for critical components is provided through room cooling systems which are powered by different MCCs.

Inverters 14 and 24: The IPEEE walkdown identified these components as potentially having inadequate anchorage. These inverters supply Panels 114 and 214, respectively. These panels provide power to the Steam Generator PORV hand controllers, so their unavailability would disable manual operation of the PORVs. However, the PORVs are not required to mitigate the consequences of the seismic event; i.e., they support no critical functions during aloss of offsite power or small LOCA.

Panel 117: Potential anchorage issues caused this panel to be noted during the IPEEE walkdown. This panel provides an alternate power supply to 120V AC Panels 111, 112, 113 and 114. The normal power supply for these panels is from their associated inverters or batteries. Since Panel 117 is a backup supply, it is not required to mitigate the consequences of a seismic accident Therefore, failure of the panel can be tolerated.

Panel 217: The IPEEE walkdown noted this panel as having shimmed anchors and, therefore, requiring further review. This panel provides an alternate power supply to Panel 1EMB, which is normally powered through 18 Inverter. Since Panel 217 is an alternate supply, it is not required to mitigate the consequences of a seismic event. Therefore, failure of this panel can be tolerated.

Panels 313 and 3133: A concern was raised during the IPEEE seismic walkdown related to the proximity of these panels to possible non-safety masonry walls. These panels are not represented in the PRA model. A review of cable data base information indicated these panels support Condensate and Feedwater systems only, which are lost as a result of the LOOP. Therefore, no further seismic evaluation is required for these components.

Panel 153: This panel was identified during the IPEEE seismic walkdown as having questionable anchorage. Panel 153 was also noted as having a potentially adverse seismic interaction. Panel 153 supports the Unit 1 Auxiliary Spray function, which is not credited in responding to the loss of offsite power/small LOCA plant condition caused by the seismic event. Based on these considerations, no further seismic evaluation is required for this panel.

Cooling Water Pump 121: SQUG and IPEEE identified anchorage and shaft stability issues for each of the diesel -driven Cooling Water pumps resulting in their being classified by SQUG as outliers. The IPEEE walkdown identified the same issues associated with the third Cooling Water pump (121). All three cooling water pumps are available to respond to a loss of offsite power/small LOCA scenario following a seismic event. The USAR states that the cooling needs for the two units can be met by one diesel driven cooling water pump when responding to a loss of offsite power. Therefore, the unavailability of 121 pump would not threaten cooling water capacity since the two diesel driven pumps both provide sufficient redundancy.

CV-31421: This valve opens to allow Auxiliary Spray flow to the 21 Pressurizer. The IPEEE walkdown identified a potentiall adverse seismic interaction involving this valve. Auxiliary spray is not credited following a seismic event as it depends on instrument air. Therefore, loss of the ability to open this valve to allow Auxiliary Spray to the Unit 2 pressurizer can be tolerated.

CV-39411: This is the 11/13 Containment FCU cooling water return valve. The IPEEE walkdown identified a potential adverse interaction involving the valve's limit switch. The interaction could cause the limit switch to become damaged and fail. The position of the valve varies depending on the time of the year and the seasonal temperature loading on the containment. To support the accident response, the preferred position of the valve is open. Should the valve be closed at the time of the seismic event, and if the limit switch should become damaged and fail due to interaction, the valve will open (the valve's fail-safe position). Based on this, no further seismic evaluation is required.

MV-32068: This normally opened valve enables SI Cold Leg injection into the Loop B Cold Leg. The IPEEE walkdown identified a potential adverse seismic interaction with the valve. However, because the valve is already in its preferred position for accident/event response, and since it is not considered credible that the seismic interaction would cause the normally open valve to change positions, no further seismic evaluation is called for.

MV-32086: This normally closed valve provides a flow path for emergency boration supply to the charging pump suction via the boric acid transfer pumps. The seismic IPEEE walkdown identified a potential adverse seismic interaction involving the valve. No credit was taken for this emergency boration function, sothe seismic interaction with

this valve would have no consequence. Therefore, no further seismic evaluation is required.

MV-32117: This valve provides isolation to the Spent Fuel Pit Heat Exchanger from Unit 2 CC and is normally in a closed position. The seismic IPEEE walkdown identified a potential adverse seismic interaction involving the valve. Following a seismic event, assuming the occurrence of a loss of offsite power and a small LOCA, there is no need for the valve to change position. In fact, it is preferred that the valve remain closed. It is not considered credible that the seismic event would cause the normally closed valve to change to the open position. Therefore, no further seismic evaluation is required for this component.

MV-32267: This is the Train B Component Cooling Water Supply valve to the 11/12 Reactor Coolant pumps. This normally open valve is required to remain open. The seismic IPEEE walkdown identified a potential adverse seismic interaction involving the valve. It is not considered credible that the seismic interaction would cause the normally open valve to change positions and become closed. Therefore, no further seismic evaluation is called for.

MV-32386: This is the cooling water supply valve to the 21 Containment FCU. This valve is normally open and is required to remain open to support the response to the post seismic event conditions postulated here. It is not considered credible that the seismic interaction would cause the normally open valve to change positions and become closed. Therefore, no further seismic evaluation is called for.

Condensate Storage Tanks (11, 21, 22): The seismic ruggedness of these tanks was called into question during the IPEEE walkdown. However, cooling water supplies from alternate sources (e.g., Cooling Water) are available such that loss of the tanks can be accommodated. Realignment to of the AFW pump suction to the alternate cooling water supply can be accomplished by the operator from the control room.

Boric Acid Filters (11, 21): The IPEEE seismic walkdown noted anchorage and support concerns related to these components. These filters remove particulates from the flow supply from the boric acid transfer pumps to charging pump suction in the emergency boration mode of operation. The emergency boration mode of operation is not credited in response to the seismic event. Therefore, the integrity of the filters during and following a seismic event is not critical to bring the plant to a safe shutdown condition.

Bus 22 Undervoltage Relays (2-27A/B22-XA and 2-27B/B22XA): The IPEEE seismic walkdown noted that the panels containing these relays have shimmed anchors and required further review. Bus 22 carries loads for the Unit 2 Reactor Coolant Pumps and the Main Feedwater pumps. In the event of a loss of offsite power, power to the Bus is lost. These relays sense the effect of an undervoltage situation during normal plant

operations and send a signal to initiate a reactor coolant pump trip which causes a reactor trip. Since the equipment supported by Bus 22 is not credited following a seismic event and a reactor trip will be accomplished from other signals, no further evaluation is required for these components.

11, 12, 21, and 22 Component Cooling Water Pump Discharge Pressure Switches (16262, 16263, 16264, and 16265): These mercoid switches are not explicitly modeled in the PRA. The IPEEE walkdown raised as a concern the functioning of these switches during a seismic event. The pressure switches are part of the CC Pump Autostart logic. The pressure switches sense low pressure in the associated pump discharge header (due to loss of one or both of the normally operating CC pumps) and starts the CC pumps. The pumps have two autostart signals: one is the pressure switch/sensor, the other is by ESF signal. There is also a manual start option. Following the seismic event, an ESF signal will cause the CC pumps to receive a start signal. The signal from these pressure switches is, therefore, not critical. No further seismic evaluation is required for these components.

Containment Pressure Transmitters (1PT-948 and 2PT-945): The IPEEE seismic walkdown identified a potentially adverse interaction for each of the racks on which these transmitters are mounted. Also, the anchorage for the rack containing 2PT-948 was noted as being questionable and needing further review. These transmitters represent a bank of six in each unit that sense rising containment pressure. At the appropriate set point and with sufficient coincidence from the other transmitters, a "P" signal is generated which, in turn, causes initiation of the Containment Spray system. No credit has been taken for Containment Spray in responding to the seismic event and the ensuing plant condition. Instead, cooling is provided by the containment Fan Coil Units (FCUs) which are sized to more than adequately handle the decay heat load. Therefore, these transmitters are not critical to the plant response to the earthquake, and they require no further evaluation.

Low Header Pressure Switches (PS-16002, 16009, 16259): These mercoid switches are not explicitly modeled in the PRA. The IPEEE walkdown raised as a concern the functioning of these switches during a seismic event. The switches are part of the start logic for the diesel-driven Cooling Water pumps (12 and 22) and the motor-driven pump (121). Similar to the logic for the pressure switches in the Component Cooling Water system, these switches detect low pump discharge header pressure and send a start signal to the associated pump-start circuit. Since the auto-start logic also accepts an ESF signal to initiate pump start, the reliability of these pressure switches during/following a seismic event is not critical. No further seismic evaluation is required for these items.

A.2.4.1.3 Outliers Potentially Addressed by Maintenance Procedures

Bus 25: A wall-hung ladder behind the bus cabinet was noted in the walkdowns. Earthquake motion could cause the ladder to slide off of the wall hooks and strike the bus

cabinet. Damage affecting the structural integrity is unlikely, but impact could cause relay chatter. Restraining the ladders to the wall hooks by chaining or an alternate means will mitigate the potential for impact. Alternatively, the ladder could be relocated sufficiently far from the bus such that impact would be unlikely.

D2 Diesel Generator Control Panel: Wall hung scaffolding is located in close proximity behind the panel. Earthquake motion could cause the scaffolding to slide off of the wall hooks, impact the panel, and potentially induce relay chatter. Restraining the scaffolding by chaining or an alternate means will mitigate the potential for impact. Alternatively, the scaffolding could be relocated sufficiently far from the panel such that impact would be unlikely.

A general maintenance provision to restrain all wall hung ladders or remove them from the proximity of essential equipment can be used to address the potential seismic interaction. This will mitigate the potential for impact induced relay chatter. A general maintenance provision is recommended since the locations of the ladders were transient.

A.2.4.2 Safe Shutdown Functions Following a Seismic Event

All the functions that are needed to ensure adequate core cooling and containment pressure control following an earthquake have multiple and, in some cases, diverse trains of equipment, each one of which is capable of performing that function. Each train of equipment for both units has been shown to be seismically rugged to the SSE level. As a result, it is concluded that the Prairie Island plant has no vulnerability to seismic events.

Reactivity Control

All systems, structures, and components (SSCs) that support reactivity control were found to be seismically rugged and would be available following an earthquake.

Given the loss of offsite power or small LOCA that is assumed to follow an earthquake, several independent signals would be expected to induce a reactor trip, such as Loss of Offsite Power and Turbine Trip. The principal means of reactor shutdown would be the Reactor Protection System effecting control rod insertion. Generic Letter 88-20, Supplement 5 [2] eliminated reactor internals from the scope of the IPEEE investigation. Therefore, no further consideration has been made as to the insertion capability of control rods when issued a scram signal.

Reactor Coolant Pump Seal Cooling

All the SSCs credited to provide Reactor Coolant Pump Seal Cooling were found to be seismically rugged to the SSE or are being evaluated for adequacy under the closure of the Prairie Island USI A-46 Program.

Two redundant and diverse means are available to provide seal cooling and prevent a potential small LOCA through failed seals. Charging pumps (two in each Unit) are available to provide seal injection cooling. Two trains of the Component Cooling Water system are also available to supply CC to maintain the RCP Thermal Barrier.

Secondary Heat Removal

All the SSCs credited to provide Secondary Heat Removal were found to be seismically rugged to the SSE, can be recovered by operator action, or are being evaluated for adequacy under the closure of the Prairie Island USI A-46 Program.

Normal secondary cooling is provided through the Main Feedwater system which is lost due to the loss of offsite power. AFW provides this cooling function by a pump backed by the Emergency Diesel Generators, or by a pump powered by a steam turbine. The turbine-driven pump trip and throttle valves were identified as potentially susceptible to tripping closed due to the seismic event. An operator action is defined in existing procedures to restore these valves so that both trains of AFW remain available.

AFW would normally be aligned to take suction from the Condensate Storage Tanks. Since these are not credited (they are not seismically designed tanks), cooling water supply is provided by the Cooling Water system which takes suction from the Mississippi River.

Short Term Inventory Control (Injection)

All SSCs credited to provide Short Term Inventory Control were found to be seismically rugged.

Both trains of Safety Injection are available to provide Short Term Inventory Control through supplies of borated water from the BAST, then from the RWST. Auto-transfer logic and valves to effect the realignment from BAST (when empty) to the RWST have been determined to be capable of surviving the seismic event.

Long Term Inventory Control (Recirculation)

All SSCs credited to provide Long Term Inventory Control were determined to be seismically rugged to the SSE level and are available to perform their intended functions.

No credit has been taken for the RCS Cooldown and Depressurization function, which involves systems such as Auxiliary Spray, RHR Shutdown Cooling, and Secondary Depressurization. Long Term Inventory Cooling Control is supported by Safety Injection in its recirculation mode of operation. After the inventory in the RWST is depleted, SI is aligned to take suction from the RHR pumps which are, in turn, taking suction from the containment sump. The sump contains the inventory spilled through the postulated small LOCA, including primary system coolant and the contents of both the BAST and RWST.

Containment Pressure Control

All SSCs associated with Containment Pressure Control were found to be seismically rugged to the SSE, or are being evaluated for adequacy under the closure of the Prairie Island USI A-46 Program.

Prairie Island has two diverse systems to provide Containment Pressure Control. The Containment Spray system has not been credited in the seismic IPEEE. Cooling of the decay heat load in the containment is provided by the Containment Air Cooling system. Four FCUs, two in each independent train, remove heat via the Cooling Water system. Each train of FCUs is sufficient to provide decay heat removal.

AC Power

All SSCs associated with AC Power system were found to be seismically rugged to the SSE, or are being evaluated for adequacy under the closure of the Prairie Island USI A-46 Program.

Both trains of Emergency Diesel Generators and associated electrical supply/distribution equipment are available in both Units following the earthquake. Therefore, no consideration has been made for the ability to cross-tie units to compensate for an unexpected loss of equipment, which represents additional margin not accounted for in this investigation. Due to the loss of offsite power, the diesels come on-line immediately and provide AC power to enable plant response throughout the event and subsequent recovery actions.

DC Power

All SSCs associated with DC Power were found to be seismically rugged to the SSE, or are being evaluated for adequacy under the closure of the Prairie Island USI A-46 Program.

Two trains in each unit are available to support vital loads such as instrumentation, reactor protection, fire protection and EDG control power.

Cooling Water

The normal water supply for the CL system is from the circulating water pump bays in the screenhouse. The three vertical safeguards pumps take a suction on an emergency bay and discharge to the common CL header. The emergency bay receives water normally from the circulating water bays through two normally open sluice gates, but also has a separate emergency supply intake pipe (36" diameter) which supplies water directly from the Mississippi River. The emergency intake line supplies water from a channel in the river at a point that assures submergence of the intake line if Lock and Dam #3 downstream of the plant were lost. The emergency intake pipe would be required

only if the normal path from the Mississippi River through the outer screenhouse were to become blocked or if Lock and Dam #3 fails. If either of these scenarios were postulated to occurr, the cooling water supply would be limited to the inventory in the intake canal plus the flow through the 36" safeguards pipe. As the flow required for two-pump operation exceeds the capacity of the safeguards pipe, operator action to reduce cooling water loads is required. These actions include isolating turbine building loads and containment fan coil units. Given the size of the intake canal, more than four hours are available to reduce and manage Cooling Water loads under these conditions. This leads to the conclusion that sufficient cooling water is available following a seismic event to enable the safe shutdown of both units as the SSCs of the Cooling Water system that are nessary to do this have been found to be seismically rugged to the SSE, or are being evaluated under the closure of the Prairie Island USI A-46 program.

Conclusions and Recommendations

As shown, all the functions for both units that are needed to ensure adequate core cooling and containment pressure control following the earthquake and the postulated events caused by the earthquake have multiple and, in some cases, diverse trains of equipment available. As a result, it is concluded that the Prairie Island plant has no vulnerabilities to seismic events.

Table A.2.4-1 Disposition of Components Not Meeting Reduced Scope Screening

Component	System	Potential Failure Mode	Conclusion
CV-39401 and CV-39409	CL	damage due to seismic-induced impact with adjacent conduit	to be addressed by SQUG outlier resolution
Containment Fan Coil Unit 13	ZC	demand exceeds capacity	to be addressed by SQUG outlier resolution
11 and 21 Batteries	DC	did not meet screening caveats	to be addressed by SQUG program outlier resolution
12 and 22 Batteries	DC	missing spacers noted in the walkdowns	to be addressed by SQUG program outlier resolution
11, 12, and 22 Battery Chargers	DC	anchorage	to be addressed by SQUG program outlier resolution
D1 and D2 Diesel Generator Gage Panels	DG	panels are supported by very flexible, unrestrained vibration isolators	to be addressed by SQUG outlier resolution
DC Panels 11, 12, and 22	DC	seismic-induced bending stresses in the anchorage	to be addressed by SQUG outlier resolution
11, 21 Screenhouse Roof Exhaust Fans	CL	anchorage	to be addressed by SQUG outlier resolution

Table A.2.4-1, continued
Disposition of Components Not Meeting Reduced Scope Screening

Component	System	Potential Failure Mode	Conclusion
12 and 22 Jacket Heat Exchangers for 12 and 22 Diesel Engines	DG	vessel sliding due to lack of structural connection between vessel and saddle supports	to be addressed by SQUG outlier resolution
12 and 22 Diesel Driven Cooling Water Pumps	CL	anchor bolts do not satisfy minimum edge distance requirements and the vertical shaft length exceeds component caveats	to be addressed by SQUG outlier resolution
MCC 1AB1 and 1AB2	AC 480	inadequate anchorage	to be addressed by SQUG outlier resolution
MCC 1K1	AC 480	relay chatter due to seismic-induced impact from wall-mounted RHR Lifting Block Fixtures	to be addressed by SQUG outlier resolution
MCC 1L2	AC 480	relay chatter due to seismic-induced impact from rod-hung piping	to be addressed by SQUG outlier resolution
MCC 2K2	2AC 480	relay chatter due to seismic-induced impact from rod-hung pipe	to be addressed by SQUG outlier resolution

Table A.2.4-1, continued
Disposition of Components Not Meeting Reduced Scope Screening

Component	System	Potential Failure Mode	Conclusion
MCC 1TA1 and 1TA2	AC 480	components are supported shims producing seismic-inducing anchor bolt bending	to be addressed by SQUG outlier resolution
MCC 2LA2	2AC 480	welded anchorage is very minimal	to be addressed by SQUG outlier resolution
121 and 122 Cooling Water Pump Fuel Oil Storage Tank	FO	undetermined flexibility of buried pipe	to be addressed by SQUG outlier resolution
121 and 123 Diesel Generator Fuel Oil Storage Tank	FO	undetermined flexibility of buried pipe	to be addressed by SQUG outlier resolution
Pressurizer Relief Valves 1RC-10-1 and 2, 2RC-10-1 and 2	RC	Floor response demand may exceed capacity	to be addressed by SQUG outlier resolution
Relay Room North (121, 122) and South (121, 122) Unit Coolers	ZH	anchorage	to be addressed by SQUG outlier resolution
121 and 122 Control Room Chillers	ZH	unrestrained vibration isolators	to be addressed by SQUG outlier resolution
Control Room Ceiling		falling ceiling diffusers	to be addressed by SQUG outlier resolution

Table A.2.4-1, continued
Disposition of Components Not Meeting Reduced Scope Screening

Component	System	Potential Failure Mode	Conclusion
Panels 132 and 133	AC	Seismic interaction	support of bus room cooling function determined to be unnecessary
11, 12, 21 and 22 RHR Unit Coolers	ZC	Structural integrity uncertain	support of room cooling function determined to be unnecessary
Switchgear/Bus Room Unit Coolers (for buses 111, 112, 121, 122, 15 and 16)	ZH	Anchorage	support of bus room cooling function determined to be unnecessary
D5/D6 480V Aux. Air Handlers (21/22) and 480V Switchgear Room Aux. Condensing Units (21/22)	DG	Anchorage	support of bus room cooling function determined to be unnecessary
11, 12, 21 and 22 Containment Spray Pumps	CS	Anchorage	not credited, redundent to containment FCUs
11, 12, 21 and 22 SG Level Logic Relays and Bistables	S signal	Anchorage and interaction	S signal source considered redundent
CV-31059 and CV-31060	AFW	seismic-induced trip of the valve trip device	Valve can be reset through operator actions

Table A.2.4-1, continued
Disposition of Components Not Meeting Reduced Scope Screening

Component	System	Potential Failure Mode	Conclusion
Air Compressors for 12 and 22 Diesel Cooling Water Pumps	CL	Anchorage	Air receivers contain enough air for diesel starting
122 and 124 Diesel Generator Fuel Oil Storage Tank	FO	undetermined flexibility of buried pipe	not credited, capacity and cross-connection of tanks 121 and 123 is sufficient
11, 12, 21 and 22 SG PORV Accumulator	MS	Anchorage	Not credited in seismic IPEEE evaluation
11, 12, 21 and 22 Boric Acid Transfer Pumps	VC	Anchorage	Not credited in seismic IPEEE evaluation
13 and 23 Charging Pumps	VC	Anchorage	Not credited due to sufficient charging capacity by pumps 11/12 and 21/22
Buses 11, 12, 13 and 14	AC	Anchorage	Do not support equipment credited to respond to plant conditions
MCCs 1M1, 1M2, 1MA1 and 1MA2	AC	Anchorage	Do not support equipment credited to respond to plant conditions

Table A.2.4-1, continued
Disposition of Components Not Meeting Reduced Scope Screening

Component	System	Potential Failure Mode	Conclusion
14 and 24 Inverters	AC	Anchorage	Do not support equipment credited to respond to plant conditions
Panel 117	AC	Anchorage	Does not support equipment credited to respond to plant conditions
Panel 217	AC	Shimmed Anchors	Does not support equipment credited to respond to plant conditions
Panels 313 and 3133	AC	Interaction	Do not support equipment credited to respond to plant conditions
Panel 153	DC	Interaction and shimmed anchors	Does not support equipment credited to respond to plant conditions

Table A.2.4-1, continued
Disposition of Components Not Meeting Reduced Scope Screening

Component	System	Potential Failure Mode	Conclusion
121 Cooling Water Pump	CL	anchor bolts do not satisfy minimum edge distance requirements and the vertical shaft length exceeds component caveats	not credited, redundant to 12 and 22 Diesel Driven Cooling Water Pumps
CV-31421	VC	Interaction	Does not support equipment credited to respond to plant conditions
CV-39411	CL	damage to limit switch due to seismic-induced impact with adjacent valve	valve fails safe, damage to limit switch will also cause valve to fail safe
MV-32068	SI	Interaction	valve already in required position and is not required to change positions, interaction not expected to cause change of position
MV-32086	VC	Interaction	valve normally closed and function not required, interaction not expected to cause change of position

Table A.2.4-1, continued
Disposition of Components Not Meeting Reduced Scope Screening

Component	System	Potential Failure Mode	Conclusion
MV-32117	CC	Interaction	valve normally closed and function not required, interaction not expected to cause change of position
MV-32267	CC	Interaction	valve already in required position and is not required to change positions, interaction not expected to cause change of position
MV-32386	CL	Interaction	valve already in required position and is not required to change positions, interaction not expected to cause change of position
11, 12, and 22 Condensate Storage Tanks	AF	inadequate anchorage	not credited
11 and 21 Boric Acid Filters	VC	Anchorage	not credited
Bus 22 UV Relays 2-27A/B22-XA and 2-27B/B22-XA	RP Signal	Shimmed anchors and interaction	Unnecessary due to redundancy in RP signal sources

Table A.2.4-1, continued
Disposition of Components Not Meeting Reduced Scope Screening

Component	System	Potential Failure Mode	Conclusion
CC Pump Discharge Pressure Switches (PS-16262 thru 16265)	CC	Mercoid switch	Auto-start function redundant to other signal sources
Containment Pressure Transmitters (1PT-948,2PT-945)	S signal	Interaction	Function not credited
CL Pump Low Header Pressure Switches (PS-16002, 16009, 16259)	CL	Mercoid Switches	Auto-start function redundant to other signal sources
D2 Diesel Generator Control Panel	DG	relay chatter due to seismic-induced impact from wall-mounted scaffolding	outlier, recommend a maintenance activity to restrain or move the scaffolding
Bus 25	2AC 4160	relay chatter due to seismic-induced impact from wall-hung ladder	outlier, recommend a maintenance activity to restrain or move the ladder

A.2.5 Analysis of Containment Performance

As indicated in NUREG-1407, the focus of the containment evaluation is to identify any severe accident issues unique to seismic events that may involve early failure of important containment functions. The containment evaluation for Prairie Island revealed no such issues. The purpose of this section is to review and discuss the containment response following a seismic event and to present the details of the containment-related evaluations that were performed for the seismic IPEEE.

A.2.5.1 Basis for the Scope of the Analysis

The scope of this containment analysis is based upon a review of the Level 2 analysis in the internal events PRA [19], as well as the specific issues presented in Section 3.2.6 of NUREG-1407. The focus of the evaluation was to identify any potential early containment failure modes unique to seismic events that had not already been evaluated as a part of the internal events PRA. This evaluation was performed assuming disposition of components requiring additional evaluation performed according to Section 2.4 had been completed.

The NUREG-1407 guidance requires an evaluation of any seismically induced containment failures and other containment performance insights. Particularly, it should consider vulnerabilities found in the systems and functions which could lead to early containment failure or which may result in high consequences. These include containment isolation, bypass, and integrity, and systems required to prevent early failure.

A.2.5.2 Containment Structures and Systems

A seismic assessment was performed to identify any vulnerability that could lead to early failure of containment functions. The structures, systems, and components needed to ensure containment integrity, containment isolation, and prevention of bypass were reviewed.

Containment Structures

The containment structures and components were evaluated as described in Section A.2.3. The Unit 1 and Unit 2 containment vessels were found to be seismically adequate for the reduced scope review. A review of the design basis seismic results (USAR) indicated that the containment vessel and components could be screened from further review based on the USAR requirements.

A general review of the Unit 1 containment penetrations did not identify any significant seismic vulnerabilities. Detailed walkdown reviews of the Unit 2 containment penetrations and components confirmed similarities to Unit 1 and also did not identify any seismic vulnerabilities. The equipment hatches, personnel airlocks, and containment penetrations do not have inflatable seals or cooling systems. Therefore, it was concluded

that the containment structures and components have no seismic vulnerabilities that could lead to early containment failure.

Containment Systems

Systems important to maintaining containment integrity after a core damage event were identified in the Prairie Island internal events PRA. A summary of these systems and the functions that they provide follows:

Containment Isolation
- Isolation Valves

Debris Cooling (In-vessel and Ex-vessel)
- High Head SI
- Low Head SI
- Containment Spray

Containment Pressure Control
- RHR (aligned for high head or containment spray recirculation)
- Fan Coil Units

Radioactive Release Control
- Containment Spray
- Fan Coil Units

For components in many of these systems, a screening evaluation was done as part of the plant walkdowns and seismic margins assessment, as discussed in Sections A.2.2, A.2.4, and A.2.5. The functions and systems listed above were reviewed to determine whether all systems which are important to containment performance were evaluated during the seismic margins assessment.

In this containment evaluation, any system or component which must be disabled in order to reach core damage was not credited as a means of avoiding containment failure. Table A.2.5-1 summarizes the systems which would be available to provide functions such as debris cooling and containment heat removal.

The accident sequence types defined in the internal events PRA are presented below. Each discussion supports the conclusions that (1) the majority of systems important to containment performance under severe accident conditions were considered as a part of the seismic margins assessment, and (2) the containment response to core damage following a seismic event is similar to that analyzed in the internal events PRA.

Containment Response

Fourteen accident classes or accident sequence types were defined in the internal events PRA. These include:

TEH	Transients (non-LOCA) in which core damage occurs at high reactor pressure without high head injection
TLH	Transients (non-LOCA) in which core damage occurs at high reactor pressure without high head recirculation
BEH	Station Blackout events leading to core damage
SEH	LOCAs in which core damage occurs at high reactor pressure without high head injection
SLH	LOCAs in which core damage occurs at high reactor pressure without high head recirculation
SEL	LOCAs in which core damage occurs at low reactor pressure without low head injection
SLL	LOCAs in which core damage occurs at low reactor pressure without low head recirculation
GEH	Steam Generator Tube Rupture in which core damage occurs without high head injection
GLH	Steam Generator Tube Rupture in which core damage occurs after RWST depletion
FEH	Internal flooding leading to core damage without high head injection
FLH	Internal flooding leading to core damage without high head recirculation
REP, RLO	ATWS leading to core damage

The two initiating events which may accompany a seismic event are a loss of offsite power or a small loss of coolant accident. These initiators are associated with the first five of the accident classes given above. For each of the first five accident classes, a comparison between the plant response as analyzed in the internal events PRA and the response that would be expected if the accident were initiated by an earthquake is described below. Because of the design capacity of the piping components that lead to eight of the remaining accident classes (medium or large LOCA, steam generator tube rupture, and floods leading to failure of multiple trains of safe shutdown equipment), the

potential for a seismic event to lead to these accident sequence types is considered to be low.

Transient or Small LOCA at High Reactor Pressure without High Head Injection (Classes TEH and SEH)

For these accident classes, core damage is assumed to occur as a result of the loss of secondary heat removal and high pressure injection in the bleed and feed mode (transient initiators). Small LOCAs are assumed to lead to core damage either as a result of loss of Safety Injection or secondary heat removal. If high pressure injection is not recovered before the core melts through the vessel lower head, then the reactor would depressurize when the lower head is breached. Both high pressure and low pressure coolant makeup systems would then be able to cool the debris in the reactor cavity. These are the same systems that were considered in the internal events PRA for debris cooling. The same systems credited in the internal events PRA for long-term decay heat removal would also be available following an earthquake: RHR and Fan Coil Units. Due to the number of systems available to provide debris cooling and decay heat removal, only a limited fraction of the sequences initiated by transients or LOCAs and having high reactor pressure would be expected to lead to early containment failure. The containment response to core damage events in these accident classes is expected to be the same regardless of whether the accident is initiated by an earthquake.

Transient or Small LOCA at High Reactor Pressure without Recirculation (Classes TLH and SLH)

For these accident classes, secondary heat removal may have been lost but Safety Injection has provided adequate core cooling. Core damage occurs as a result of the inability to establish high head recirculation. For these accident sequences, the RWST contents have been injected to containment and reactor cavity level is such that the lower vessel head is submerged. Heat transfer through the lower head to the water in the reactor cavity is likely to be sufficient to prevent lower head penetration. As long as a containment heat removal system is available, such as the Fan Coil Units, the core damage event can be terminated within the vessel. Containment response to seismic events leading to this accident class results in no early or late containment challenges that were not already identified in the internal events PRA.

Station Blackout (BEH)

The potential for core damage due to station blackout sequences results primarily from battery depletion. If no AC power source is recovered within the first four to six hours of the blackout, the uncooled core debris in the vessel could melt

through the lower head and enter the containment. A part of the core debris would be entrained in the steam during vessel blowdown and carried in to the upper compartment of containment. The rest would remain in the reactor cavity. Early challenges to containment for a core damage event resulting from a station blackout are the same as considered in the internal events PRA. If no means of cooling the debris or removing decay heat from the containment is recovered, the containment would eventually pressurize; however, this would take place so slowly that it would take roughly a day or more to reach the containment failure pressure. The timing and response of the containment to severe accident conditions associated with a seismically initiated station blackout are very similar to the internal events PRA.

Table A.2.5-1 provides a summary of Level 1 to Level 2 dependencies for these accident classes.

Containment Isolation

Isolation valves are provided on all lines penetrating the containment to assure its integrity under accident conditions. Those isolation valves which must be closed to assure containment integrity immediately after a major accident are automatically controlled.

Many different types of penetrations were considered during the containment isolation evaluation of the internal events PRA. The following piping and hatch penetration groups were examined:

- Safety Injection lines
- RHR lines
- Containment Spray lines
- Component Cooling lines
- Cooling Water lines
- Purge and vent lines
- Containment sump discharge and suction lines
- Containment vacuum breaker lines
- Equipment hatch, and personnel and maintenance airlocks
- Fuel transfer tube
- Instrument Air lines
- Instrument and sample lines
- Charging and letdown lines
- RCP seal cooling lines
- Steam generator blowdown lines

- Feedwater, auxiliary feedwater, and main steam lines
- Fire Protection lines

The first two penetrations listed are important when analyzing the potential for containment bypass or interfacing systems LOCAs, because breaks or leaks in such lines could result in releases directly from the reactor vessel into the plant buildings. However, since these piping systems are seismically rugged, they do not contribute significantly to the potential for containment bypass following a seismic event.

The remaining penetrations and piping must remain intact or be isolated to prevent flow from the containment atmosphere into the auxiliary building or outdoors. If radionuclides are released into the containment or the containment becomes pressurized as a result of an accident, isolating the containment minimizes any releases to the outside atmosphere and avoids potential adverse impacts on accident mitigating systems in the auxiliary building. The following considerations were used to help focus the review of penetrations and piping in these groups:

- Penetrations of open containment or reactor systems: If the system is not connected to the containment atmosphere or the reactor coolant system, the probability of simultaneous failure of the isolation valve(s) in the system and a pipe break is negligibly small.

- Pipes with diameters greater than 2 inches: These pipes are considered to contribute most significantly to the magnitude of release following containment isolation failure. Furthermore, aerosol plugging is likely to reduce the amount of leakage that could occur from smaller penetrations.

- Hatches and airlocks: These items are closed during operations as part of technical specification requirements.

- Normally closed lines: Lines containing normally locked closed valves, or lines containing closed valves that would not be expected to open during the course of an accident do not contribute significantly to containment isolation failure.

Table A.2.5-2 shows the containment penetrations that remain for further consideration using the criteria given above. The table shows the configuration of the containment isolation valves, their normal positions, the signals required to close the valves, and the dependencies of the valves on support systems for motive and control power.

The isolation valves in this table are the same as those considered in the internal events PRA. It should be noted that many of these isolation valves are either normally closed or they fail closed on the loss of air or control power. These valves are designed such that the potential for containment isolation following a seismic event is high and can be considered similar to that evaluated for the internal events PRA.

Table A.2.5-1 Prairie Island Level 1 to Level 2 Dependencies

Accident Class	Secondary Heat Removal			Debris Cooling						Containment Control		
				Injection			Recirculation					
	AFW	MFW[1]	SG[2] PORV	SI	PZR[2] PORV	CS[3]	SI Recirc	RHR Recirc	CS[3] Recirc	RHR	FCU	CS[3]
TEH	-			✓[6]			✓[6]	✓		✓	✓	
BEH	✓			✓[4]			✓[4]	✓[4]		✓[4]	✓[4]	
SEH	✓[5]			✓[6]			✓[6]	✓		✓	✓	
TLH	-			7			-	✓		✓	✓	
SLH	✓[5]			7			-	✓		✓	✓	

1 Assumed not to be available as a result of loss of offsite power
2 Assumed not to be available as a result of not crediting instrument air
3 Not credited in the Seismic IPEEE
4 On AC power recovery
5 Provided reason for core damage is not secondary heat removal failure
6 Provided reason for core damage is not SI failure
7 Function successfully performed as a part of Level 1
✓ Credited in the Level 2 analysis
\- Failed as a part of Level 1

Table A.2.5-2 Contributors to Containment Isolation Failures

Description	Penetration Number	Size	Configuration	Position	Signals	Power/Air
Letdown line	11	2"	1 NC MOV in parallel with 4 AOVs: 1 NO in series with 3 in parallel (1 NO and 2 NC)	NO	Containment Isolation	AOVs fail closed on loss of air or DC
Charging line	12	2"	2 CV, 1 AOV	NO	None	AOV fails closed on loss of air or DC
RCP seal water supply	13A	2"	2CV in series	NO	None	None
RCP seal water supply	13B	2"	2 CV in series	NO	None	None
Instrument air	20	2"	2 AOVs in series	NO	Loop A MSL isolation, hi-hi containment pressure	AOVs fail closed on loss of air or DC
Containment sump A discharge	26	3"	2 AOVs in series	NO	Containment Isolation	AOVs fail closed on loss of air or DC
Containment vacuum breaker	41A	18"	1 AOV and 1 air-assist CV in series	NO	Containment Isolation	AOVs fail open on loss of air or DC
Containment vacuum breaker	41B	18"	1 AOV and 1 air-assist CV in series	NO	Containment Isolation	AOVs fail open on loss of air or DC
Post-LOCA H2 control air	42A	2"	1 MOV and 1 CV in series	NC	None	MOV fails as-is on loss of AC
Air vent	42A	2"	1 AOVs and 1 MOV in series	NC	None	AOVs fail closed on loss of air; MOV fails as-is on loss of AC
Reactor makeup to PRT	45	2"	1 AOV and 1 CV in series	NC	Containment Isolation	AOV fails closed on loss of air or DC
Post-LOCA H2 control air	50	2"	1 MOV and 1 CV in series	NC	None	MOV fails as-is on loss of AC
Air vent	50	2"	1 AOVs and 1 MOV in series	NC	None	AOVs fail closed on loss of air; MOV fails as-is on loss of AC

A.2.6 Conclusions and Recommendations

The significant conclusions from the IPEEE seismic evaluation of essential Prairie Island structures and components for both Units 1 and 2 are that:

- Class I structures were reviewed and were screened from any further seismic analysis based on the adequacy of the design basis USAR criteria. Seismic gaps between structures were considered during the IPEEE seismic walkdowns and were found to be consistent with design specifications.

- Masonry walls were evaluated and found to be seismically adequate to the SSE and were screened from any further review.

- Mechanical and electrical equipment, heat exchangers, and certain tanks are adequate to retain their structural integrity and post-earthquake functionality. Some equipment was identified in the IPEEE investigation as being questionable, but these are either being addressed through the closure of the Prairie Island USI A-46 Program or have been shown to have no significant consequences if they were to fail.

- Distributed systems such as piping, cable trays, conduit, and HVAC ducting were verified to be seismically adequate.

- There are no "bad actor" relays unique to the IPEEE equipment and systems credited for plant response for core cooling and containment pressure control.

The majority of equipment included in the scope of the Prairie Island seismic margins assessment are seismically rugged and meet the screening criteria in EPRI NP-6041-SL. The components that were found to be questionable in maintaining structural integrity and functionality were either already identified as "outliers" within the Prairie Island USI A-46 Program, or were shown to have no significant consequence in ensuring adequate core cooling and containment pressure control. A general maintenance provision to restrain all wall-hung ladders or remove them from the proximity of essential equipment can be used to address the potential seismic interaction. This will mitigate the potential for impact-induced relay chatter. A general maintenance provision is recommended since the locations of the ladders were transient.

The containment response to a severe accident following a seismic event is expected to be similar to that analyzed for the internal events PRA. No early containment failure modes unique to a seismic event were identified as a part of this analysis.

A.2.7 Unresolved Safety Issues and Other Seismic Safety Issues

1. USI A-17 [16] systems interactions were considered in the IPEEE seismic walkdowns and seismic margin evaluations. Any significant seismic systems interactions were identified in the IPEEE walkdowns. USI A-17 is concerned with operational dependencies between systems. A qualitative analysis of these dependencies was considered in assessing the availability of plant functions following a seismic event. Insights from the internal events PRA were instrumental in this task.

2. USI A-40 [17] includes the seismic analysis of above-ground tanks. Most tanks important to the operation of the systems credited in the seismic margins assessment were found to have sufficient seismic capacity to meet the screening criteria of EPRI NP-6041-SL. The condensate storage tanks were not credited as a water source in the seismic margins assessment and therefore were not evaluated in the IPEEE.

3. The seismic walkdowns for the IPEEE were conducted following the initial walkdowns for USI A-46, "Verification of Seismic Adequacy of Equipment in Operating Plants [4]." Since these efforts were conducted in parallel, significant information was shared between the two programs. The walkdown data obtained for the USI A-46 activities was made available for IPEEE.

4. USI A-45 [18] addresses the adequacy of the heat removal function at operating plants. There are four possible methods of decay heat removal at Prairie Island: secondary cooling through the steam generators with Main Feedwater and Auxiliary Feedwater providing steam generator makeup, bleed and feed cooling utilizing the SI pumps and pressurizer PORVs, RCS injection and recirculation as provided by the SI and RHR systems (primarily for medium and large LOCAs), and Shutdown Cooling (SDC) mode of RHR operations after RCS has been cooled down and depressurized to RHR SDC conditions.

   Heat removal through the steam generators is the primary and preferred method of decay heat removal until the RCS pressure drops to the point where RHR SDC can be placed in service. Under normal conditions, Main Feedwater provides secondary cooling to the steam generators. However, in the event of an earthquake and associated loss of off-site power, Main Feedwater is unavailable. Steam generator makeup is then provided by Auxiliary Feedwater. Two trains of Auxiliary Feedwater were evaluated and found to be seismically rugged to SSE levels. The availability of these trains of AFW in each unit ensure adequate steam generator makeup and decay heat removal.

   Bleed and feed cooling and the Shutdown Cooling mode of RHR are both assumed to be unavailable following the seismic event. Bleed and feed depends on pressurizer PORV operation. However, the PORVs are, in turn, dependent on instrument air to maintain a charge in the accumulators associated with the valves. Instrument air is not seismically designed and has been assumed to have failed due to the earthquake. There is sufficient air in

the PORV accumulators to support a limited number of cycles of PORV operation but not enough to sustain bleed and feed operation. The Shutdown Cooling mode of RHR is not credited in the IPEEE due to the unavailability of equipment to effect depressurization of the RCS and the secondary system. With the primary system pressurized, short and long term cooling is provided by SI in injection and recirculation modes.

SI is initiated immediately after the earthquake due to the assumption that the loss of off-site power is accompanied by a small LOCA. SI initially operates in the injection mode, providing primary coolant makeup from first the BAST, then the RWST. Collectively, these supplies of borated water are substantial but are expected to be depleted as their inventory is injected into the RCS and spilled through the small LOCA breach. As the RWST approaches depletion, SI and RHR transition to recirculation mode in which the RHR pumps take suction from the containment sumps and supply the suction to the SI pumps. This establishes a long term cooling "loop" that removes decay heat from the reactor and releases it through the RHR heat exchangers to the CC system.

Whereas steam generators/AFW and SI/RHR provide for reactor core decay heat removal, two systems exist to provide containment pressure control to compensate for decay heat rejected to the containment. Containment Spray, a system that sprays down the internal space within containment, was not credited in the IPEEE. Instead, Containment Air Cooling has been evaluated and found to be seismically rugged to the SSE. Four fan coil units (FCUs) are configured in two separate trains, each consisting of two FCUs. The FCUs are sized such that each can absorb 50% of the heat load to containment in the design basis accident. Two functioning FCUs, therefore, ensure adequate containment pressure control.

The decay heat removal (DHR) issue was examined as part of the IPE, the details of which are contained in Section 3.4.4 of the IPE submittal. The results of the seismic analysis for loss of DHR did not differ significantly from the loss of DHR evaluated in the IPE.

Prairie Island's means of dealing with decay heat removal during accidents involving seismic events is similar to that described in the internal events IPE and is considered adequate to resolve this generic issue.

5. GI-131 [29] includes the seismic analysis of the moveable incore flux mapping system at Westinghouse plants. A walkdown was performed together with a seismic margins analysis of the flux mapping systems for both units. The mounting and the flux mapping system itself were found to have sufficient seismic capacity to the SSE level of the USAR.

6. Charleston Earthquake Issue:

   The NRC states in Generic Letter 88-20, supplement 4, that the Charleston Earthquake Issue is subsumed in the IPEEE. NSP has performed a seismic margins assessment for the Prairie Island IPEEE and therefore has fulfilled the requirements for this issue.

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Prairie Island
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NSPLMI-96001

Appendix B
Revision 1

Internal Fires Analysis

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B.1 INTRODUCTION

B.1.1 Background

The assessment that is described in this appendix addresses the internal fires requirements of Supplement 4 to Generic Letter (GL) 88-20, "Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities" [1], for the Prairie Island Nuclear Generating Plant. The fire analysis performed for the IPEEE began in 1992 and reflects plant changes made since the Individual Plant Examination was submitted in February, 1994 [2]. This internal fire assessment combines the probabilistic risk assessment approach used in the IPE with the deterministic evaluation techniques of the Electric Power Research Institute's Fire Induced Vulnerabilities Evaluation (FIVE) methodology [4].

B.1.2 Plant Familiarization

Units 1 and 2 of the Prairie Island Nuclear Generating Plants are 2-loop PWRs with large dry containments. Westinghouse Electric Corporation designed and supplied the nuclear steam supply system and the turbine-generator units. Pioneer Service and Engineering (now Fluor Power Services, Inc.) was the plant's architect-engineer. Northern States Power constructed the plant. Each reactor core produces 1650 MWt with an electrical output of 560 Mwe, using 121 fuel assemblies. The plant is located within the city limits of Red Wing, Minnesota. Construction started on June 26, 1968 and full commercial operation began on December 16, 1973 for Unit 1 and December 21, 1974 for Unit 2.

Implementation of the requirements of 10 CFR 50, Appendix R, contributed significantly to the low overall risk due to fires at the Prairie Island facility. These requirements addressed issues such as fire barriers and penetration seals, administrative control of combustibles, fire brigade training and equipment, and protection of safe shutdown equipment. Fulfillment of these requirements resulted in physical modifications to the plant, including installation of Remote Shutdown Panels, re-routing of safe shutdown cables, and upgrading of fire barriers. The Nuclear Regulatory Commission's (NRC) Inspection Report, dated August 19, 1988, documented the satisfactory resolution of the sections of 10 CFR 50, Appendix R, applicable to Prairie Island.

B.1.3 Overall Methodology

The Prairie Island fire study uses an approach that combines the deterministic evaluation techniques from the FIVE methodology with classical PRA techniques. The FIVE methodology provides a means of establishing fire boundaries as well as methods to evaluate the probability and the timing of damage to components located in a compartment involved in a fire. PRA techniques allow determination of compartment-specific core damage frequencies associated with fires within the various fire areas of the plant. For the Prairie Island Fire IPEEE, compartments were identified and evaluated, then quantified using the fault trees and event trees from the updated internal events PRA.

The transient and small LOCA event trees from the internal events PRA and related fault trees were used to perform the quantification. These events were used because of evaluations which indicate that postulated fires at Prairie Island could result in these types of events. The resulting accident sequences were binned into three accident classes and subclasses, a subset of those used in the internal events PRA. These accident classes and their relative contributions are shown in Figure B.1.4-1. The contribution of specific areas to the core damage frequency is shown in Figure B.1.4-2.

B.1.4 Summary of Major Findings

The principal finding of this analysis is that there is no credible single fire in the plant that would lead directly to the inability to cool the core. Without additional random equipment failures unrelated to damage caused by the fire, core damage will not occur. As a result, this study concludes that there are no major vulnerabilities due to fire events at the Prairie Island Nuclear Generating Plant.

The core damage frequency resulting from fires is estimated to be approximately 6.3E-5/year. The total CDF for fire-induced core damage sequences is on the same order of magnitude as the core damage frequency for the internal events PRA. While this is consistent with the results of internal fire analyses at other sites, it should be noted that these results include a number of conservative assumptions. For example, automatic or manual fire suppression was not credited except in the Control Room, Relay Room, and AFW pump rooms. Fires were also assumed to completely engulf an area once ignited, unless suppression occurs.

From Figure B.1.4.1, the core damage frequency is spread across three accident classes: early core melt with the reactor at high pressure (TEH), late core melt at high pressure (TLH), and early core melt at high pressure in conjunction with a small LOCA (SEH). Together these three classes account for nearly 100% of the core damage associated with internal fires.

Accident class TEH is comprised of transient (i.e., fire) initiated events with loss of secondary heat removal (loss of MFW and AFW) and failure of bleed and feed. Reactor pressure is high at the time of core damage. Core damage occurs within approximately 2 hours of the loss of heat removal.

Accident class TLH is characterized by transient initiated events with loss of secondary heat removal, successful bleed and feed but failure of recirculation. Reactor pressure is high at the time of core damage, which occurs on the order of 10 hours after the loss of secondary cooling.

The SEH accident class for the IPEEE consists of RCP seal LOCA initiated events in which high head safety injection is not capable of preventing core damage. Reactor pressure is high at the time of core damage, which occurs relatively early (see TEH).

As shown in Figure B.1.4-2, 95% of the plant risk associated with internal fires can be traced to nine fire areas/burn areas. These rooms/burn areas are:

1. Auxiliary Building Ground Floor Unit 1 (FA 58),

2. 480V Safeguards Switchgear Room—Bus 121 (FA 22),
3. Turbine Building Ground & Mezz Floor Unit 1 (FA 05, 08, 14, 21, 27, 57, 69, 94),
4. Relay (cable spreading) Room (FA 18),
5. 4KV Safeguards Switchgear Room—Bus 15 (FA 81),
6. 480V Safeguards Switchgear Room—Bus 111 (FA 80),
7. Train "B" Hot Shutdown Panel and Air Compressor/AFW Room (FA 32),
8. Control Room (FA13), and
9. Train "A" Hot Shutdown Panel and Air Compressor/AFW Room (FA 31).

Auxiliary Building Ground Floor Unit 1 (FA 58)—44.0% of Total Internal Fire CDF

A fire in this area could lead to failure of many components necessary for safe shutdown of the plant. Both trains of Safety Injection, RHR and Component Cooling as well as all three charging pumps are located in this area. This is an extremely large area with significant distance between sets of components. Fire wrapping of critical power and control cables provides protection for Train "B" equipment. A train of component cooling is available to prevent an RCP seal LOCA.

480V Safeguards Switchgear Room—Bus 121 (FA 22)—14.1% of Total Internal CDF

Bus 121 powers a number of the Train B 480V components. Equipment affected by a fire in this area includes the #11/13 Charging pumps, #12/22 AFW pumps, #122 Instrument Air compressor, #12, 14, 18 and 28 inverters, and #21 cooling water pump. Due to the electrical equipment located in this area, electrical fires are the most significant ignition sources. The #11 AFW pump and main feedwater are available to provide secondary cooling.

Turbine Building Ground & Mezzanine Floor Unit 1 (FA 05, 08, 14, 21, 27, 57, 69, 94)—10.2% of Total Internal Fire CDF

Fires in this combined area are relatively frequent and severe (compared to other areas) due to the higher potential for turbine oil and gas fires. A fire in this area has the potential to fail all of main feedwater and a train of AFW. Both feedwater pumps and all three condensate pumps are physically located in this area. Other key components located in this area are the main power cables between safeguards 480V AC Bus 121 and auxiliary building MCCs 1K2 and 1KA2, which supply power to two of the three charging pumps, component cooling water valve MV-32094, cooling water valve MV-32146 as well as Train B safety injection valves.

Control Room, Relay Room (FA 13, FA 18)—3.1%, 6.2% of Total Internal Fire CDF

If not suppressed by automatic or manual equipment, a fire in the Control Room or Relay Room is assumed to cause loss of all equipment not controlled from the hot shutdown panels (HSDPs). The HSDPs assure the ability to shut down the plant in the event of a fire in either of these areas. Successful fire suppression in the Control Room or Relay Room limits the damage to a single

cabinet in either area, where it is assumed the fire started. The single cabinet (one in each area) contains cables for both MFW and AFW, and is considered to be the worst case fire location within either space. Equipment available following successful suppression includes all other equipment normally controlled from the Control Room. Key systems available at the HSDPs include AFW and Charging. The availability of these systems from the HSDPs limits the risk significance of fires in the Control Room and Relay Room areas.

4KV Safeguards Switchgear Room—Bus 15 (FA 81)—5.8% of Total Internal Fire CDF

A fire in the Bus 15 switchgear results in damage or loss of Train A components. The affected equipment consists of the #11 SI pump, #11 RHR pump, #11 Component Cooling pump, and power to Buses 111 and 112. Control cables for Feedwater and Condensate pumps also transit this space. Systems available for S/G makeup include #11 and #12 AFW trains. Electrical equipment comprises the majority of the ignition sources.

480V Safeguards Switchgear Room—Bus 111 (FA 80)—4.7% of Total Internal Fire CDF

A fire in the 111 bus room can result in damage or loss of a number of components. This equipment includes the #12 Charging Pump, 121 Instrument air compressor, component cooling water valve MV-32093 (CC to 11 RHR heat exchanger), and Train A safety injection valves. Also, power for RWST to charging system make-up valve MV-32060 is obtained from Bus 111. Electrical equipment comprises the majority of the ignition sources. Unit 1 AFW operation is not affected by fires in this area.

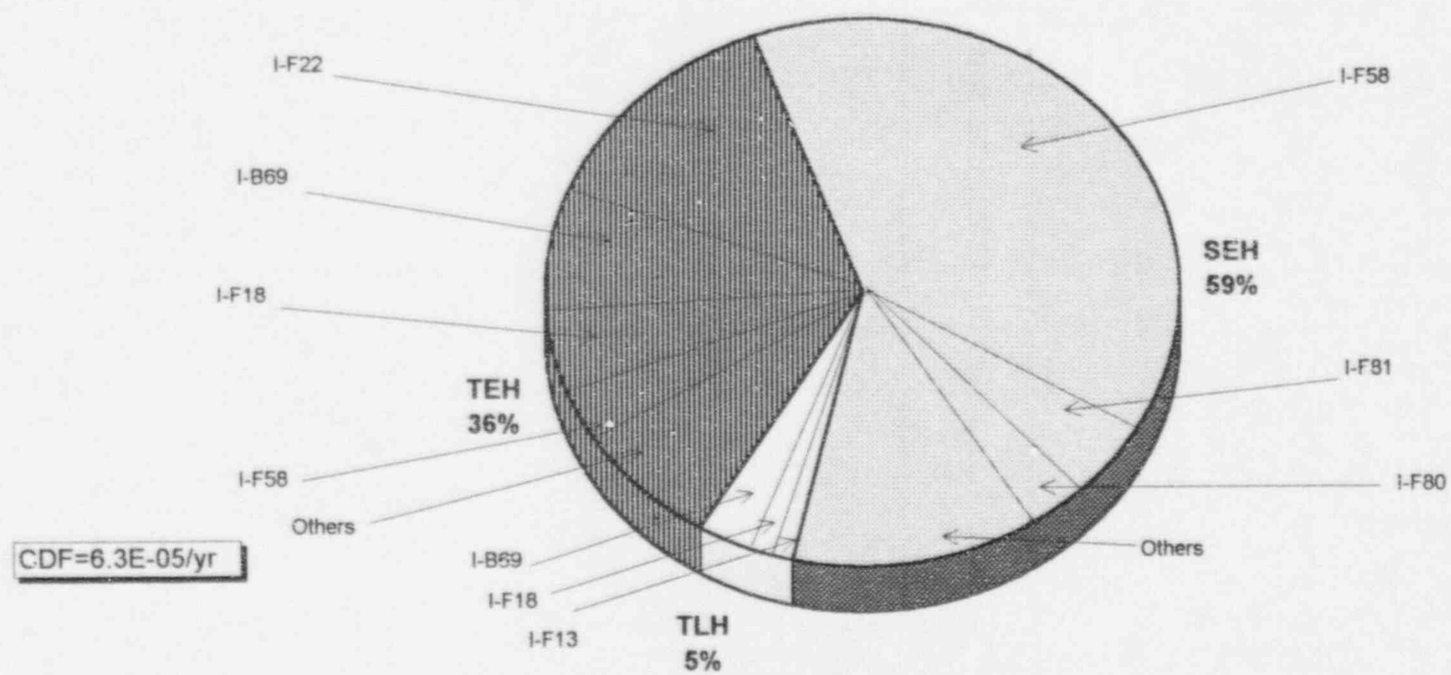
"B" Train Hot S/D Panel & Air Comp/AFW Room (FA32)—3.6% of Total Internal Fire CDF

The #11/21 AFW pumps, instrument air compressors 121 and 122, MCCs 1A1 and 1A2, and the "B" Hot S/D panel are located in this area. In addition to the equipment physically located in the area, power to MCC 1K1 and various other Train A components are routed through this area. Since the manual valve used to crosstie the Service Air system to Instrument Air is located in this area, it was not credited during fires in this space. Automatic wet pipe suppression is available and was credited in this area.

"A" Train Hot S/D Panel & Air Comp/AFW Room (FA 31)—2.9% of Total Internal Fire CDF

Similar to FA 32, the #12/22 AFW pumps, instrument air compressor 123, MCCs 2A1 and 2A2, and the "A" Hot S/D panel are located in this area. In addition to the equipment physically located in the area, and various other Train B components are routed through this area. Crosstie to the Service Air system is available following the failure of the Instrument Air system. Automatic wet pipe suppression is available and was credited in this area.

Figure B.1.4.1 - Prairie Island Fire PRA
Core Damage Frequency by Accident Class



NOTE: Arrows indicate fraction of accident class CDF due to most significant fire areas in each accident class

Figure B.1.4.1 Core Damage by Accident Class

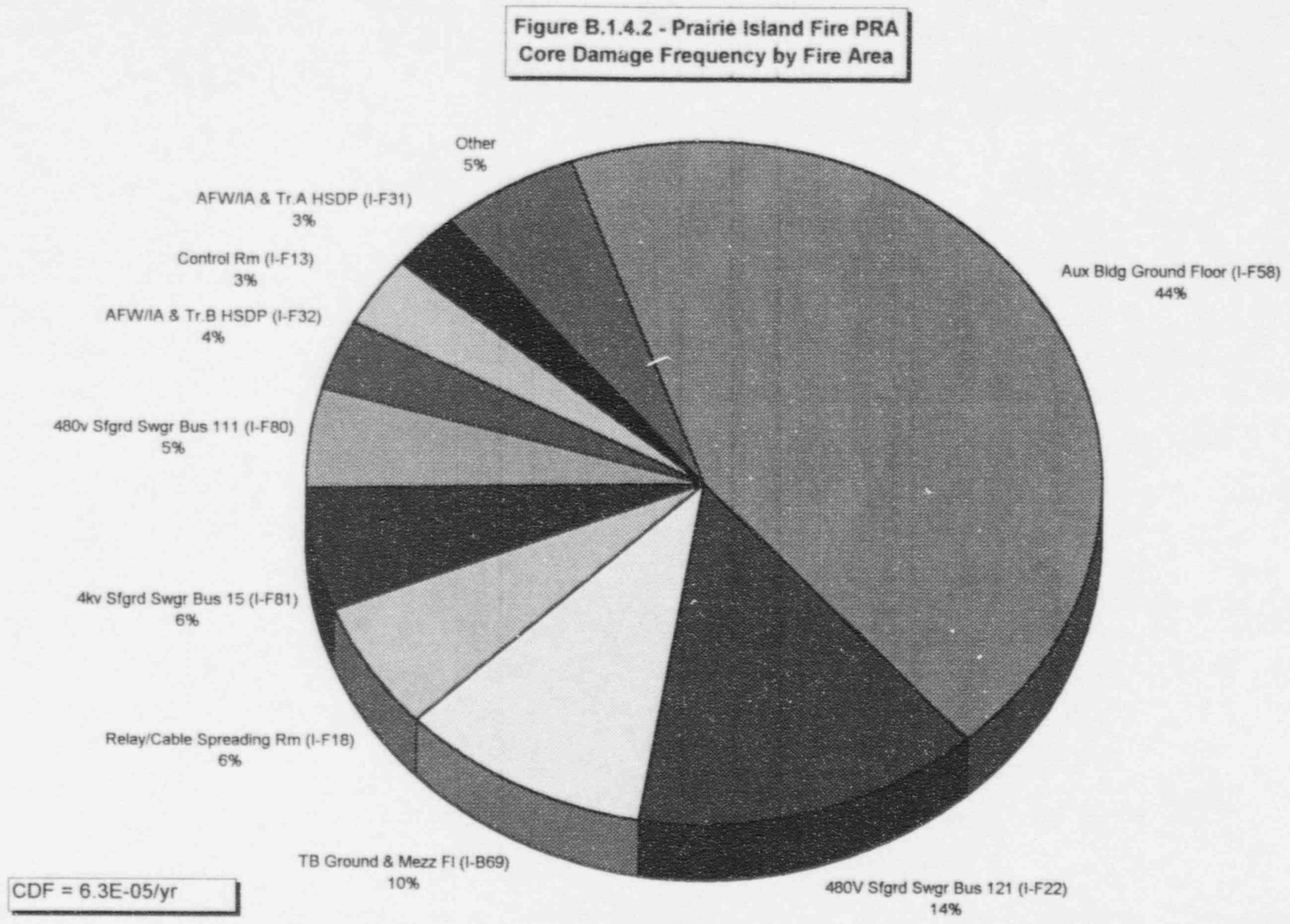


Figure B.1.4.2 Core Damage by Fire Area

B.2 INTERNAL FIRE ANALYSIS

B.2.1 Fire Analysis Methodology

This fire analysis combines the deterministic evaluation techniques of the FIVE methodology with PRA methods. The flow chart in Figure B.2.1.1 illustrates the process used to quantify accident sequences for the Prairie Island fire IPEEE. Phase I is a deterministic evaluation of fire spread and ignition source frequencies. Phase II is a probabilistic evaluation of core damage using PRA techniques. If conditional core damage frequencies are unacceptable following completion of Phase I, Phase II continues with a deterministic evaluation of the effects of fire suppression and fire propagation. The FIVE methodology is used to establish fire boundaries and to evaluate the probability and the timing of damage to components located in a compartment involved in a fire. PRA techniques are used to determine compartment-specific core damage frequencies for fires within specific fire areas.

Fire areas: The Appendix R fire areas for Prairie Island are defined in Table B.2.1.1. For this IPEEE fire analysis, those areas outside the main reactor/turbine building complex which meet both of the following criteria were screened from further consideration:

1. The area contains no system credited in the internal events PRA; cables supporting those systems are also not present in the area.

2. A fire in the area would cause no demand for safe shutdown functions because the operating crew can maintain normal plant operations.

In applying this criteria only fire areas outside the auxiliary/turbine building complex were screened from further evaluation.

Spread of fires across boundaries: The spread of fires across fire area boundaries is addressed in the FIVE methodology. The following criteria are used in the FIVE methodology to identify boundaries which can be considered to prevent the spread of a fire:

1. Boundaries between two zones, neither of which contains safe shutdown components nor components whose failure could result in the initiation of a plant trip, on the basis that a fire involving both zones would have no adverse effect on safe shutdown capability.

2. Boundaries that consist of a 2-hour or 3-hour rated fire barrier, on the basis of fire barrier effectiveness.

3. Boundaries that consist of a 1-hour rated fire barrier with a combustible loading in the exposing zone (the zone containing the initiating fire) of less than 80,000 Btu/ft^2, on the basis of fire barrier effectiveness and low combustible loading.

4. Boundaries where the exposing zone has very low combustible loading (<20,000 Btu/ft^2), on the basis that manual suppression will prevent fire spread to the adjacent zone.

5. Boundaries where both the exposing zone and exposed zone (the zone threatened by the exposing fire) have a very low combustible loading (<20,000 Btu/ft^2), on the basis that a significant fire cannot develop in either zone.

6. Boundaries where automatic fire suppression is installed over combustibles in the exposing zone, on the basis that this will prevent fire spread to the adjacent zone.

The first criterion was not credited in the Prairie Island fire IPEEE. That is, the potential for a fire to spread was evaluated whether or not there was safe shutdown equipment or the potential for a plant trip in a given area. This is based on the conservative assumption that any fire will result in at least a manually initiated plant shutdown.

If any one of criteria 2, 3 or 5 were met, the potential for fire spread through or across the common boundary was assumed to be negligible. These three criteria credit fire boundary ratings and combustible loading.

Criteria 4 and 6, in which fire suppression is credited, were not initially applied, to allow future evaluation of the impact of suppression and because the probability of automatic fire suppression systems failing to actuate is non-negligible. If any of the compartment fire events led to dominant core damage sequences without consideration of suppression, the effect of fire suppression was then evaluated in a probabilistic manner. This approach allowed identification of fire suppression systems that have the greatest impact on fire-induced core damage.

The groupings of fire compartments due to fire spread potential are presented in section B.2.5 and shown in Table B.2.6.3.

Systems credited: Before fire sequence quantification could be performed, it was necessary to identify the functions and systems to be included in the fire IPEEE. The associated equipment and cables and respective locations were then identified using plant documents (see section B.2.3) in conjunction with the Prairie Island internal events PRA and a plant walkdown. As a result of this assessment, all systems credited in the IPE analysis were also credited in the fire IPEEE analysis.

Accident sequence evaluation: The next phase of the analysis was a multi-step, progressive probabilistic evaluation that considered the sequence of events that must occur to create the loss of safe shutdown/risk-significant functions. Figure B.2.1.1 shows the flow path and the major steps in the process. These steps consist of determining ignition source frequencies and quantifying specific fire scenarios. Following accident sequence quantification, the impact of fire suppression and the potential for the fire to propagate to identified targets was considered for risk significant areas. The potential impact on containment performance and isolation was evaluated following the core damage assessment.

The first step of the accident sequence quantification was to identify and tally the ignition source frequencies in each compartment. These sources were identified during the first walkdown and a

compartment-specific ignition frequency was calculated in accordance with the methods detailed in FIVE. Section B.2.6 details the actual methodology used in these calculations.

The next step, quantifying specific fire scenarios, was performed using the ignition source information in conjunction with the fire spread and fire effects information developed in Phase I. All the basic events in the logic models of the internal events PRA related to cables or components in the burning location were assumed to be failed. At this point in the evaluation, it was assumed that all equipment and cabling within the affected fire area or sub-area was destroyed. The core damage frequency for each of the fire areas and burn sequences was then quantified using the internal events PRA fault tree and event tree models. Fires in the Control Room and Relay Room included additional actions and assumptions that were incorporated into event trees developed explicitly for these rooms. The quantification yielded a core damage frequency (CDF) for each area by incorporating the area-specific ignition frequencies and crediting the unaffected systems or trains included in the internal events PRA.

The final step was to evaluate the impact of the fires on the containment structure and function. Containment structural evaluations included factors such as combustible loading in and around the containment. The potential for containment isolation or bypass was also investigated. Most containment isolation valves fail in a safe (closed) position. Multiple failures are required to bypass the containment. Because of these and other factors, containment integrity is expected to be maintained following any postulated fire. A more detailed description of these analyses is contained in Section B.2.12.

Uncertainties: Most of the uncertainty in the results is centered around assumptions made in the accident sequence quantification. These assumptions include those regarding credit for various systems and operator actions that may occur in response to a fire as well as those implicit in the deterministic evaluation of plant response to a fire such as that contained in the FIVE methodology or experimental studies.

As examples, automatic and manual fire suppression were not credited except in the Control Room, Relay Room, and AFW pump rooms. Fires were assumed to completely engulf the area in which they started. If deterministic methods had been applied to show the limit of the fire spread, core damage may have been reduced. Wherever possible, assumptions such as these were made in a conservative manner to bound uncertainties.

Assumptions incorporated into risk-specific areas within the plant include the likelihood of fire propagation along horizontal cable trays (fire areas 58/73) and fires that are successfully suppressed in the Relay Room and Control Room. While there may be uncertainties associated with these assumptions, their application is supported by deterministic or experimental evidence under specific conditions. Further, the overall conclusions of the fire IPEEE can be shown to be insensitive to these particular uncertainties. That is, there is no one area in the Prairie Island plant in which a fire could start that does not require additional failures unrelated to the fire before inadequate core cooling would result.

Table B.2.1.1 Prairie Island Appendix R Fire Areas

AREA NUMBER	AREA DESCRIPTION	AREA SQ. FT.	TOTAL BTU (10^6)	FIRE LOADING BTU/FT^2
1	Containment Unit 1	8,660	659.1	76109
2	Ventilation Fan Floor, Unit 1	9,570	263.6	27,544
3	Water Chiller Room, Unit 1 (121)	1000	42.4	42450
4N	Fuel Handling Area	4,670	121.8	26,082
5N	Old Admin Bldg (Elev. 715')	3,522	60.7	17,235
6N	Old Admin Building, HVAC Area (Elev. 750')	1,540	6.24	4,052
7N	Old Admin Building Office Area (Elev. 735')	7,532	64.0	8,497
8N	Turbine Deck (Units 1 & 2)	54,870	8.9	162
9N	Maintenance Shops	6,550	7.92	1209
10	Train "A" Event Monitoring Equipment Room	530	14.0	26,430
11	Unit 1 Normal Swgr. & Control Rod Drive Room	2,250	29.2	13000
12	OSC Room	1,000	31.2	31,180
13	Control Room	4,160	262.2	63,029
14N	Working Materials Storage & Lunch Room	6,550	3.45	527
15	Access Control	3,060	85.8	28,039
16	Train "B" Event Monitoring Equipment Room	520	24.1	46,352
17	Unit 2 Normal Swgr. & Control Rod Drive Room	2,250	28.7	12,764
18	Relay and Cable Spreading Rm., Unit 1 & Unit 2	4,160	1,684.1	404,829
19N	Computer Room	980	9.8	10,000
20	Unit 1 4KV Safeguards Swgr. (Bus 16)	760	78.8	103,734
21N	Unit 1 4KV Normal Swgr. (Bus 13,14)	1,690	15.3	9053
22	480V Safeguards Swgr. (Bus 121)	770	62.9	81,805
23N	Unit 2 4KV Normal Swgr. (Bus 23, 24)	1,690	25.5	15,089
24N	Oil Storage Area	1,350	2,934	2.17×10^6
25	Diesel Gen #1 Room	1,460	159.2	109,041
26	Diesel Gen #2 Room	1,350	157.2	116,444
27N	Water Conditioning Equipment Area	3,800	16.4	4,316
28aN	Transformer 1GT	(2)	2,526	N/A
28bN	Transformer 2GT	(2)	2,526	N/A
28cN	Transformer 1R	(2)	1,132	N/A
28dN	Transformer 1M	(2)	678	N/A
28eN	Transformer 2M	(2)	678	N/A
28fN	Transformer 2RX & Y	(2)	746	N/A
29	Admin Building Electrical & Piping Room #1	1,100	44.1	40,091
30	Admin Building Electrical & Piping Room #2	1,100	42.8	38,955
31	"A" Train Hot S/D Panel & Air Compressor/AFW Room	1,180[1] 2,360[1]	130.2	36,780
32	"B" Train Hot S/D Panel & Air Compressor/AFW Room	1,180[1] 2,360[1]	124.1	35,064

Table B.2.1.1(continued) Prairie Island Appendix R Fire Areas

AREA NUMBER	AREA DESCRIPTION	AREA SQ. FT.	TOTAL BTU (10^6)	FIRE LOADING BTU/FT^2
33	Battery Room 11	590	11.7	19,966
34	Battery Room 12	590	16.4	27,864
35	Battery Room 21	590	11.9	20,305
36	Battery Room 22	590	16.3	27,746
37	Unit 1 480V Normal Swgr. (Bus 150, 160)	1,030	44.4	43,172
38	Unit 2 480V Normal Swgr. (Bus 250, 260)	1,100	42.6	38,788
39N	Radiation Waste Building	2,990	29.3	9,799
40N	Cooling Towers 121,122, 123, 124	(2)	(2)	*
41A	Screenhouse (DDCWP Room)	1,840	199.2	108,283
41B	Screenhouse Basement	4,220	134.1	31,770
41N	Screenhouse (General Area)	(2)	(2)	*
42N	Cooling Tower Pump House	3,670	67.8	18,474
43N	Unit 2 Transformer Oil Sump	(2)	(2)	(2)
44N	Unit 1 Transformer Oil Sump	(2)	(2)	(2)
45N	Fuel Oil and Transfer House	100	(2)	(2)
46N	Cooling Tower Equipment House & Transformers	1,620	68.7	42,407
47N	Cooling Tower Transformer Oil Sump	(2)	(2)	(2)
48N	D1, D2 Diesel Fuel Oil Storage Tanks	N/A (2)	11,260	N/A (2)
49N	Heating Boiler Fuel Oil Storage Tanks	N/A (2)	10,110	N/A (2)
50N	Cooling Tower Control House 121 & 122	990	(2)	(2)
51N	Neutralizer Tank Pump House/Warehouse #2	212.5	(2)	(2)
52N	Parking Lot	(2)	(2)	(2)
53N	Receiving Warehouse, NPD Office & NPD Annex	(2)	(2)	(2)
54N	Cooling Tower Control Hose 123 & 124	990	(2)	(2)
55N	Warehouse #1 and Fab Shop	(2)	(2)	(2)
56N	Drum Storage Area	(2)	(2)	(2)
57N	Gas House	650	7.57	11,646
58	Aux Building Ground Floor Unit 1	14,560	473.8	32,541
59	Aux Building Mezzanine Floor Unit 1	10,700	829.9	77,570
60	Aux Building Operating Floor Unit 1	6,880	101.7	14,776
61	Aux Bldg Anti "C" Clothing (El. 735')	6,330	99.6	15,731
61A	Aux Bldg Hatch Area (El. 755')	12,440	100.9	8,114
62N	Spent Fuel Pool Area	4,180	(2)	(2)
63N	Filter Room	2,430	(2)	(2)
64N	Aux Building Low Level Decay Area, Unit 1	830	2.6	3,133
65N	Spent Fuel Pool HX & Pumps	1,090	(2)	(2)
66	Storage Room D3 Room	1,470	(2)	(2)
67N	Resin Disposal Building	2,680	68.84	25,687
68	Containment Annulus Unit 1	1,710	25.5	14,906
69	Turbine Building Ground & Mezz Floor Unit 1	21,680	3,262.5	150,484
70	Turbine Building Ground & Mezz Floor Unit 2	21,680	3,103.1	143,132

Table B.2.1.1(continued) Prairie Island Appendix R Fire Areas

AREA NUMBER	AREA DESCRIPTION	AREA SQ. FT.	TOTAL BTU (10^6)	FIRE LOADING BTU/FT^2
71	Containment Unit 2	8,660	722.1	83,383
72	Containment Annulus Unit 2	1,710	25.6	14,965
73	Aux Building Ground Floor Unit 2	13,420	478.7	35,671
74	Aux Building Mezz Floor Unit 2	10,700	836.9	78,215
75	Aux Building Operating Floor Unit 2	6,880	103.6	15,055
76	Vent and Fan Room Unit 2	9,570	296.0	30,930
77N	Aux Building Low Level Decay Area, Unit 2	830	(2)	(2)
78N	Waste Gas Compressor Area	1,510	0.3	199
79	480V Safeguards Swgr Room (Bus 112)	400	11.3	28,363
80	480V Safeguards Swgr Room (Bus 111)	870	39.02	44,853
81	4KV Safeguards Swgr Room (Bus 15)	860	38.7	45,005
82	480V Safeguards Swgr Room (Bus 122)	380	9.63	25,339
83N	Inst. Lab Area, Operator's Lounge Area	1,490	2.1	1,409
84N	Counting Room & Labs	6,680	2.3	344
85N	Holdup Tank/ Demineralizer Area	4,880	(2)	(2)
86N	Intake Screenhouse, Envir Lab, Rad Monitor Station & De-Icing Pump House	(2)	(2)	(2)
87N	Deepwell Pump House #1	110	(2)	(2)
88N	Deepwell Pump House #2	110	(2)	(2)
89N	Guardhouse	3,074 3,140 (Note 3)	(2)	(2)
90N	Emergency Generator Building Security Diesel	570	72.5	127,193
91N	Diesel Fuel Pump & Decay Cooling Water Pump Oil Storage Tanks	N/A	6,205	N/A
92	Water Chiller Room Unit 2 (122)	1,000	44.45	44,450
93N	Drum Storage/Low Level Radwaste Warehouse	12,400	(2)	(2)
94N	Service Building/ Computer Area	(2)	(2)	(2)
95N	D5 Diesel Fuel Oil Storage Tanks	N/A (2)	4,862	N/A (2)
96N	D6 Diesel Fuel Oil Storage Tanks	N/A (2)	4,862	N/A (2)
97	D5 Basement (El. 687')	2,100	185.6	97,000
98	D6 Basement (El. 687')	2,330	185.6	97,000
99N	Stairwells (El. 695',707' & 718')	N/A (2)	N/A (2)	N/A (2)
100N	#21 D5/D6 Fuel Oil Receiving Tank	429	2,098	4.9×10^6
101	D5 Diesel Generator Room	1,980	154.5	86,000
102	D6 Diesel Generator Room	1,980	153.7	86,000
103	D5 Emergency Diesel Generator Control Room	550	10.3	21,000
104	D6 Emergency Diesel Generator Control Room	550	10.1	20,000
105N	D5 Battery Room	550	4.9	9,400
106N	D6 Battery Room	550	4.5	9,100
107	D5 Inverter Room	460	1.3	3,000

Table B.2.1.1(continued) Prairie Island Appendix R Fire Areas

AREA NUMBER	AREA DESCRIPTION	AREA SQ. FT.	TOTAL BTU (10^6)	FIRE LOADING BTU/FT^2
108	D6 Inverter Room	460	2.0	4,300
109	D5 Normal MCC & Cable Tray Area	1,450	74	56,000
110	D6 Normal MCC & Cable Tray Area	1,600	70	48,000
111	D5 Building - Mezzanine Floor Elev. 718'	440	13	32,000
112	D6 Building - Mezzanine Floor Elev. 718'	440	13	33,000
113	#21 D5 Fuel Oil Day Tank Room	125	88	700,000
114	#22 D6 Fuel Oil Day Tank Room	215	88	700,000
115	#21 D5 Lube Oil M-U Tank Room	90	123	1.4×10^6
116	#22 D6 Lube Oil M-U Tank Room	90	123	1.4×10^6
117	4KV Bus 25; MCC-2TA1	1,480	68	51,000
118	4KV Bus 26; MCC-2TA2	1,400	53	42,000
119	#21 D5 Ht/Lt M-U Tank Pump Room	510	4.2	9,300
120	#22 D6 Ht/Lt M-V Tank Pump Room	510	4.2	9,300
121N	Stairwell (El. 735')	402	N/A (2)	N/A (2)
122	480V Bus 221/222 Room	1,650	23	15,400
123	D5 Radiator Room	1,280	9.2	8,200
124	D6 Radiator Room	1,280	9.6	8,500
125	D5 Fan Room	1,280	N/A (2)	N/A (2)
126	D6 Fan Room	1,280	N/A (2)	N/A (2)
127	480V Bus 211/212 Room	1,480	24	17,600
128N	4KV Bus 27 Room	224	* (2)	* (2)
129N	D5 Radiator Exhaust (Roof)	1,280	N/A (2)	N/A (2)
130N	D6 Radiator Exhaust (Roof)	1,280	N/A (2)	N/A (2)
131N	New Admin Building	(2)	(2)	(2)

1 Loading based on 1180 sq. ft. for oil, 2360 sq. ft. for cable; total BTU value based on *total* sq. ft. for fire area.

2 Entries in columns are taken directly from Prairie Island Fire Hazards Analysis (F.5, App. 5), Table 6–2. Blanks, "N/A" or "*" are as found in that table, and indicate that the FHA concluded that a fire in the area has not effect on plant shutdown; no safe shutdown equipment is located in that area.

3 First entry is ground level, second is basement level.

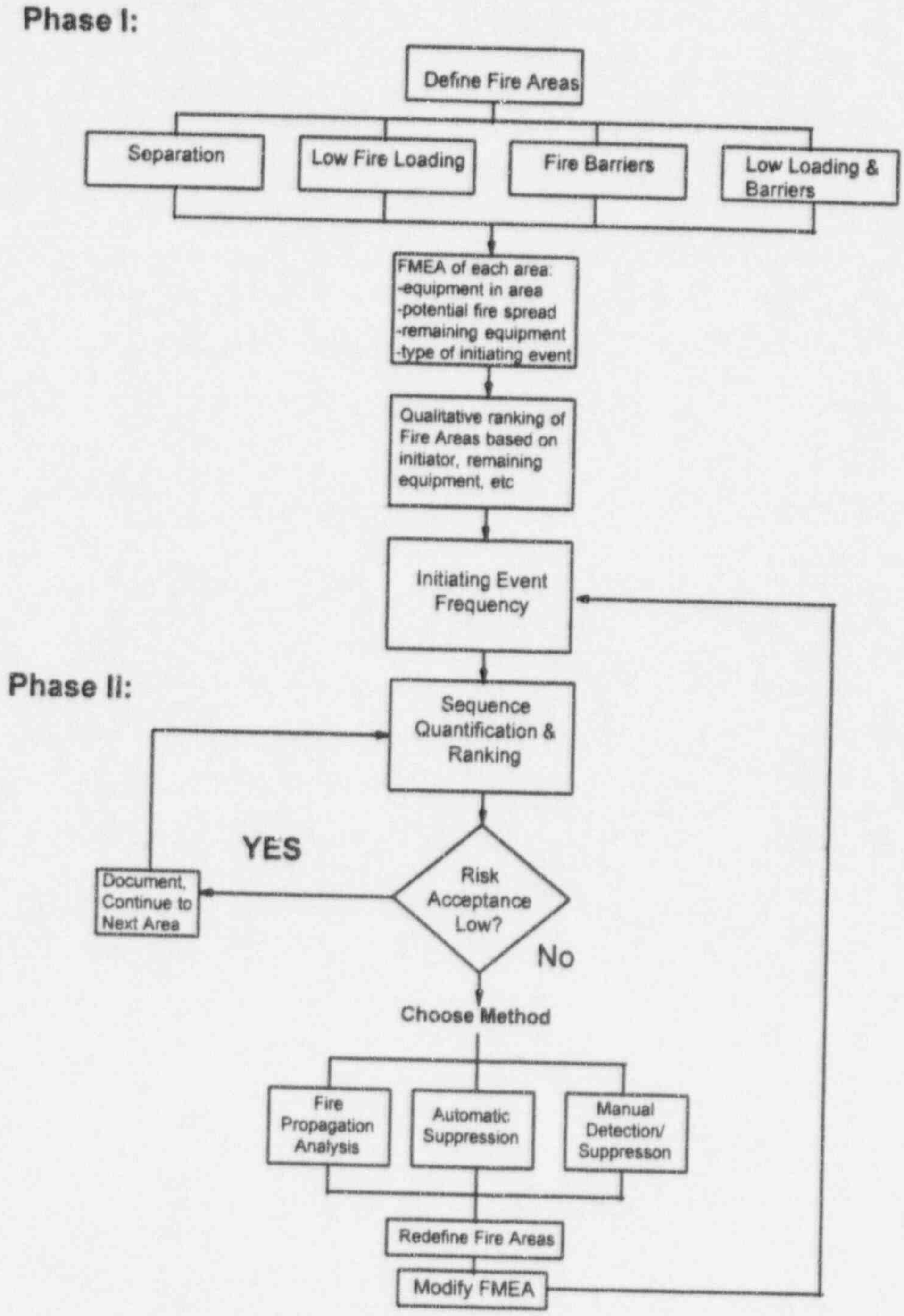


Figure B.2.1.1 Fire PRA Flow Chart

B.2.2 Modeling Assumptions

The following key assumptions were made in this analysis:

1. Loss of offsite power initiating event was found to be unlikely for a fire in any area.
2. The impact of fires on plant risk was quantified using the internal events PRA general transient event trees. Fires that lead to a loss of Reactor Coolant Pump (RCP) seal cooling are assumed to lead to a RCP seal LOCA. These fire sequences transfer from the transient event tree to the internal events small LOCA event tree model. These event trees were selected because they most closely represent the plant response given the systems being modeled.
3. ATWS events are not modeled due to the extremely low probability of an event involving a fire coincident with a failure of the reactor protection system to function.
4. Large LOCAs (LLOCAs), medium LOCAs (MLOCAs), and steam generator tube ruptures (SGTRs) are not expected to be induced by a fire; simultaneous occurrence of these events during a fire is probabilistically insignificant.
5. Reference 10 indicates that the likelihood of significant fire spread in horizontal cable trays located in cable tunnels or corridors is negligible. If the only combustible material located in a fire area is a cable insulation, a fire initiating in that area is not likely to spread. Therefore, fires in horizontal cable trays are normally self-extinguishing. For those cable fires that did not immediately self-extinguish during the tests supporting Reference 10, the maximum propagation length was approximately seven feet. It was therefore assumed that fires would not propagate in the cable trays across the fire area boundary separating fire areas 58 and 73 prior to extinguishing themselves or being suppressed.
6. Fires are assumed to spread until they engulf the entire sub-area in which they start unless the fire is suppressed. For this evaluation, no credit was taken for suppression except in the Control, Relay, and AFW pump rooms.
7. Hot shorts were not considered for the fire IPEEE evaluation. The occurrence of hot shorts was considered to be probabilistically insignificant. This is consistent with similar assumptions made in other fire analyses.

B.2.3 Review of Plant Information and Sources

Several sources of information were reviewed and used in support of the Prairie Island fire IPEEE. The information sources most often consulted were the Prairie Island Individual Plant Examination (IPE) [2], the Prairie Island Fire Hazards Analysis [7], the Prairie Island Fire

Protection Safe Shutdown Analysis Engineering Report [3], and the Fire-Induced Vulnerability Evaluation (FIVE) Report [4]. A complete list of the references used in support of this project is contained in Section B.2.16.

The IPE was used to identify important systems and functions and provided the base fault trees and event trees used to quantify the fire-related plant risk. The IPE also provided detailed information on support systems for the important front-line systems.

The Fire Hazards Analysis provided information on combustible loading, detection and suppression capabilities, and fire barrier ratings for fire areas within the plant. This document also provided floor plans showing each fire barrier and identified adjacent and adjoining fire areas. The fire area interaction analysis used the information contained in this document. The floor plans contained in the Fire Hazards Analysis which were useful in the IPEEE are included in this appendix as Attachment 1.

Prairie Island system functional block diagrams and existing 10CFR50 Appendix R data were reviewed to determine the cables necessary for operation of the components included in the models. These documents were the primary sources used to identify the cables that required tracking.

The Prairie Island cable tracking database from the plant information computer (CHAMPS) was then used to identify each of the cable trays and conduits containing these cables. The cable trays and conduits were then related to specific fire areas using the "Cable Node System" drawings. The result of this research was a database that contained information about cable and component locations and linked this information to basic events contained in the Prairie Island IPE.

This information was then used to develop a spatial database to aid in identifying, for example, all equipment impacted by a fire in a given area, or all cables and components associated with a particular event failure.

Key information contained within these records include:

Equipment/cable ID #
Related IPE event (relates equipment/cable to basic or developed event)
Equipment location (for actual components)
Cable location (fire area)
System designator
Cable raceway designator
Comments

B.2.4 Plant Walkdown

A series of walkdowns of the plants were performed in support of the IPEEE analyses. At a minimum, a senior reactor operator and a fire IPEEE analyst participated in all walkdowns. Fire

protection and electrical system engineers were called upon as issues and questions arose, principally during the final walkdown, to confirm key assumptions used in the IPEEE.

B.2.4.1 Objectives of Plant Walkdown

The primary objectives of the walkdown were to gather data, confirm information and assumptions, and complete the NUREG/CR-5088 "Fire Risk Scoping Study" evaluation [11]. The walkdown was used to determine whether the assumptions and calculations, particularly fire barrier effectiveness assumptions, can actually be supported by the physical conditions that exist. This included verifying and validating (1) the combustible loading estimates in the fire hazards analysis, (2) the existence of fire protection systems, (3) fire barrier status, (4) interaction of fire areas, and (5) verification of ignition sources. The cable tracking database, used to identify cable routing and locations, was also checked to ensure that it was up-to-date.

B.2.4.2 Walkdown Process

During the walkdown, a pre-printed data sheet for each compartment was completed. This data sheet contained estimates, based on equipment layout drawings, of the number and type of ignition sources located in each compartment. The sheets also contained general comment sections where the analyst noted any unique or unexpected features (combustible loading, smoke paths, fire barrier status, etc.) that could impact the analysis.

Important areas of the plant, as determined by the results of the fire IPEEE quantification, and areas of the plant that required validation of assumptions made during the analysis were inspected during the walkdown. Potential fire spread paths, equipment orientation, and fire barriers were also inspected.

B.2.4.3 Findings from Plant Walkdown

Several general findings were made during the walkdown. Boundary ratings were found to be generally conservative since there was a lack of combustible loading in close proximity to the barriers. The general condition of the plant was clean and well kept. If a compartment presented a significant ALARA concern and the area could not be inspected from the outside, the compartment was not inspected. Instead, plant documents and operator knowledge formed the basis for analysis of these spaces. These spaces and general information, other than ignition sources, are identified and documented in a walkdown summary. Specific findings which were generated during the plant walkdown are described below.

To address the NUREG/CR-5088 "Fire Risk Scoping Study" issues, as required for the external events fire analysis, inadvertent operation of a fire suppression system that could disable both trains of a system was investigated. The investigation was focused on areas where sprinkler heads or deluge systems might inadvertently operate.

From the Fire Hazards Analysis the areas containing automatic fire suppression systems was determined. This information was combined with walkdown observations to isolate any areas where multiple trains of a system might be impacted by inadvertent operation of the suppression

system. Due to equipment separation, only Fire Areas 31 and 32 were identified in which multiple trains could be impacted.

Fire Areas 31 and 32 each contain an AFW pump for each unit. In addition, Area 31 contains one instrument air compressor and two air compressors are located in Area 32. Due to the physical arrangement of the equipment in these areas, it is unlikely that operation of a single sprinkler head would adversely affect both AFW pumps and air compressors. Therefore, multiple sprinklers must actuate for these components to be threatened.

Due to the reasons described, inadvertent fire suppression system operation is not considered to be a credible mechanism for disabling systems at Prairie Island.

A single fire that disables all offsite power sources could have a significant impact on plant risk. For this reason, a walkdown of the turbine building 4KV areas was performed to determine whether this scenario was possible. It was noted that power feeds from all sources (1R, 2R, CT-11 and CT-12 transformers) are not routed together in the same fire area anywhere in the turbine building. The turbine building contains all the buses fed by these sources. Fires in the bus rooms are prevented from propagating to fail all sources by fire barriers. This arrangement ensures a single fire will not damage all offsite power feeds.

A review was performed to assure the reliability of the database that was used in cable identification. Administrative cable and raceway controls are in effect that provide a systematic way of tracking and entering all cable modifications and data changes occurring in the plant. It was determined that these as well as other supporting procedures provide the controls and record-keeping necessary to ensure that the database is accurate and up-to-date.

B.2.5 Identification of Important Fire Areas

The Appendix R fire areas provide the starting point for this analysis. In accordance with Appendix R requirements and the Prairie Island Fire Hazards Analysis, a fire area is defined as a portion of a building that is separated from other areas by boundary fire barriers. Only a single train of safety equipment is allowed within a given fire area unless the redundant train is protected by additional separation requirements detailed in Appendix R of 10CFR50. The FIVE boundary evaluation criteria used to define burn sequences are similar to those originally used for defining Appendix R fire areas. These criteria include spatial separation of components and cables, combustible loading, and/or construction barriers. The boundary criteria are found in the FIVE methodology and are discussed in Section B.2.1.

Fire areas for Unit 1 and common Unit 1/Unit 2 areas are described below.

B.2.5.1 Reactor Building

The Appendix R analysis divides the Unit 1 Reactor building into two fire areas: the containment (fire area 1) and the containment annulus (fire area 68). These fire areas were so divided to facilitate detailed evaluation of the effects of fire within this structure. The fire area boundaries and interfaces are described below.

The containment is a cylindrical concrete and steel structure that houses reactor coolant system components and the steam generators. The containment is completely enclosed by a secondary structure: the shield building. The containment annulus abuts the auxiliary building to the north and west between the 695' and 755' elevations. This interface consists of a three-hour fire-rated reinforced concrete barrier. Exterior walls are located along the south.

A significant fire in the containment is not likely given its combustible loading and physical configuration. Much of the combustible material located in the containment is lube oil for the reactor coolant pumps. An oil collecting system that collects the oil in the event of a spill is installed. The remaining combustible material, electrical cable, located in these areas is fire retardant (IEEE-383 rated). Because of these factors, a significant fire within the containment is not expected to occur. The FIVE methodology recognizes the unlikely occurrence of a containment fire and does not provide an ignition source frequency for this area.

B.2.5.2 Auxiliary Building

The auxiliary building is located between the reactor building to the south and the turbine building to the north, sharing a common interface with each building. The Unit 1 and Unit 2 auxiliary buildings share a common boundary and are essentially mirror images of each other. This common boundary runs in a north/south line and is a combination of hard walls and some open spaces.

The Appendix R analysis divides the Unit 1 auxiliary building into eleven fire areas (2, 3, 10, 11, 12, 15, 58, 59, 60, 64, 79) unique to Unit 1 and nine fire areas (4, 13, 18, 19, 61, 62, 63, 84, 85) shared by both units.

The auxiliary building is separated from the turbine building by 18" thick reinforced concrete walls. The auxiliary building is also separated from the diesel generator and maintenance work areas to the east by 18" reinforced concrete walls. The floors and ceilings in the auxiliary building are concrete and 12" or greater in thickness. All of these boundaries are rated as three-hour fire boundaries or equivalent.

Much of the equipment shown to be significant in the PRA is located in the lower level of the auxiliary building (695'). This level of the auxiliary building is approximately 165' by 100' in size. The space contains component cooling pumps and heat exchangers, all three charging pumps, both safety injection and containment spray pumps, as well as the RHR pumps and heat exchangers.

B.2.5.3 Turbine Building

The turbine building shares a common wall with, and is located due north of, the auxiliary building. This structure contains seventeen Appendix R fire areas divided between the two units. Battery and switchgear rooms are located along the common wall separating the two units on the 695' and 715' levels. This common separating wall is an 18" thick reinforced concrete wall with an opening protected by automatic close (gravity assist) fire doors. The turbine deck (735' level)

is a single fire area shared by both units. The fire area boundaries and interfaces are described below.

The ground level of the turbine building is at the 695' elevation. This level contains ten fire areas, eight of which are battery and switchgear rooms located along both sides of the common wall separating the two units. The rooms and corridors along the north and east perimeter are included in fire area 9 with the remaining rooms contained in fire area 10. The south wall, a three-hour rated concrete wall, forms a common boundary with the lower level of the auxiliary building. With the exception of the Train A switchgear room, the same fire areas continue upward to the next level.

The second level of the turbine building, 715', is comprised of eight fire areas (20, 21, 22, 23, 69, 70, 80, 81) with the majority of the level included in fire areas 69 and 70. Similar to the lower level, electrical switchgear rooms are located along the boundary separating the two units. The auxiliary building abuts the major portion of the south wall. The new diesel generator building also shares a common wall along the southwest corner of the structure. Reinforced concrete or masonry block fire walls separate the two units from each other and from adjoining structures.

The highest level (turbine deck - 735') is encompassed by a single fire area, fire area 8. This area shares a common wall with the auxiliary building to the south and with the old administration building along a short portion of the north wall. Separating the turbine building and the auxiliary building are a 3 1/2" insulated metal panel and an 18" thick reinforced concrete wall.

B.2.5.4 Diesel Generator Building

Appendix R Fire Areas 97-130: These fire areas contain emergency diesel generators D5 and D6, their respective fuel oil day tanks and other support equipment. The north half of the building houses D5 and the south half of the building houses D6. These areas are attached to the southwest corner of the turbine building. The interface between the DG building and the turbine building is a 20" concrete wall with an equivalent fire rating of three hours.

Because a fire in any of these rooms will not spread into the spaces containing equipment necessary for operation of the other DG, this building was partitioned into two burn sequences (B101 and B102). B101 consists of spaces containing D5 and its support equipment and B102 includes spaces containing D6 and its support equipment. Contribution to core damage due to a fire in these areas is included in the cumulative results.

B.2.5.5 Screenhouse

The plant screenhouse is divided into three fire areas, 41N, 41A and 41B. Fire area 41N is the general area on the 695' elevation. Fire area 41A is the safeguards area on the 695'

elevation. It contains the two diesel cooling water pumps and their auxiliaries, the 121 vertical motor-driven cooling water pump, MCCs 1AB1 and 1AB2, 230V AC panels 136 and 137, and the cooling water strainers. Area 41B represents the 670' elevation, which contains the fire pumps, the two non-safeguards motor-driven cooling water pumps, and the circulating water pumps. With respect to the fire PRA, the critical components located in these areas that are lost are the electrical MCCs and panels, the cooling water pumps and the fire pumps (however, only very limited credit was given for fire suppression, see Section B.2.8). A fire in any one of the sub-areas does not spread to the other areas due to spatial separation and three-hour fire barriers. Also, because of its remote location, a fire in the screenhouse does not spread to any other fire areas.

B.2.6 Fire Ignition Data

It is necessary to calculate ignition source frequencies for each area to allow quantification of the impact of a fire in each sub-area. These individual impacts can be summed to yield the impact to the plant from all fires.

The EPRI "Fire Event Database for U.S. Nuclear Power Plants" [8] was used to estimate fire ignition source frequencies for all rooms in the plant. This database contains a total of 800 events during a period from 1965-1988. These events were compiled from 114 BWR and PWR units across the United States, representing a total sample of approximateiy 1300 reactor years of operation. The data includes fire incidents caused by both fixed and transient sources due to normal operations and maintenance activities.

FIVE incorporated this information into a procedure to develop ignition source frequencies for individual fire areas and sub-areas. This process was used to evaluate the ignition frequencies (F_1) for each fire compartment. An ignition source data sheet was completed for each room or fire compartment that was contained within the fire sub-areas defined in Phase I.

The four-step process identified in the FIVE methodology was used to develop the ignition source data sheet. The first step requires that the location which corresponds best to the fire compartment in question be selected. Some locations may be specific Appendix R fire areas, such as the Control Room and Relay Room, while other locations may be general, such as turbine building fire area 69.

The second step requires that a location weighting factor (WF_L) be determined from this classification. The weighting factor is used to translate the generic fire frequencies for a location, compiled in FIVE (Table B.2.6.1), to specific, single-unit fire frequencies. The location weighting factors are designed to account for the relative amount of ignition sources in the plant in question compared to the average plant. These factors are easily calculated using the simple formulas found in Table B.2.6.1.

The third step requires that weighting factors for each type of ignition source (WF_{LS}) be determined. The potential ignition sources in each room were obtained from the Appendix R fire analysis, equipment drawings, and a walkdown of each compartment. The amount of cabling

and electrical cabinet contribution for each fire compartment was also obtained from the Appendix R fire analysis. Some ignition sources, such as cables and transformers, are best apportioned on a plant-wide basis. Once the number of plant-wide ignition sources was identified, the WF_{LS} was determined by dividing the number of components in the room by the total number of similar components in the building or generic location being considered.

The fourth step requires that the fire compartment fire frequency (F_1) be calculated for each fire compartment. Table B.2.6.2 lists the fire frequency for each ignition source (F_f) by location. F_1 is the sum of the ignition source frequencies for each ignition source (F_{if}) located within the given fire compartment. This value was obtained for each fire compartment by multiplying:

1. The fire frequency for each ignition source (F_f) (Table B.2.6.2),
2. The weighting factor for the location (WF_L) (Table B.2.6.1), and
3. The weighting factor for each ignition source (WF_{LS}) (Table B.2.6.2).

$$F_{if} = F_f * WF_{LS} * WF_L$$

This calculation was repeated for each ignition source in the compartment and the total fire frequency for the specific fire compartment (F_1) was calculated as:

$$F_1 = \sum F_{if} .$$

The resultant ignition frequencies for each compartment are provided in Table B.2.6.3.

Table B.2.6.1 Weighting Factors for Adjusting Generic Location Fire Frequencies for Application to Plant-Specific Locations (taken from FIVE methodology)

PLANT LOCATION	WEIGHTING FACTORS[1] (WF_L)
Auxiliary Building (PWR)	The number of units per site divided by the number of buildings.
Diesel Generator Room	The number of diesels divided by the number of rooms per site.
Switchgear Room	The number of units per site divided by the number of rooms per site.
Battery Room	The number of units per site divided by the number of rooms per site.
Control Room	The number of units per site divided by the number of rooms per site.
Cable Spreading Room	The number of units per site divided by the number of rooms per site.
Intake Structure	The number of units per site divided by the number of intake structures.
Turbine Building	The number of units per site divided by the number of buildings.
Radwaste Area	The number of units per site divided by the number of radwaste areas.
Transformer Yard	The number of units per site divided by the number of switchyards.
Plant-Wide Components (Cables, transformers, elevator motors, hydrogen recombiner/analyzer)	The number of units per site.

1. The analyst must identify the number of like locations when determining the number of buildings, e.g., a 480-volt load center is "like" a switchgear room.

Table B.2.6.2 Fire Ignition Sources and Frequencies by Plant Location

Plant Location	Fire Ignition/Fuel Source	Ignition Source Weighting Factor (WF_L)	Fire Frequency[1,2] (F_f)
Auxiliary Building	Electrical cabinets	B	1.9×10^{-2}
	Pumps	B	1.9×10^{-2}
Diesel Generator Room	Diesel generators	A	2.6×10^{-2}
	Electrical cabinets	A	2.4×10^{-3}
Switchgear Room	Electrical cabinets	A	1.5×10^{-2}
Battery Room	Batteries	A	3.2×10^{-3}
Control Room	Electrical cabinets	A	9.5×10^{-3}
Relay Room	Electrical cabinets	A	3.2×10^{-3}
Screenhouse	Electrical cabinets	A	2.4×10^{-3}
	Fire Pumps	A	4.0×10^{-3}
	Others	A	3.2×10^{-3}
Turbine Building	T/G Excitor	B	4.0×10^{-3}
	T/G Oil	B	1.3×10^{-2}
	T/G Hydrogen	B	5.5×10^{-3}
	Electrical cabinets	B	1.3×10^{-2}
	Other pumps	B	6.3×10^{-3}
	Main feedwater pumps	A	4.0×10^{-3}
	Boiler	B	1.6×10^{-3}
Radwaste Area	Miscellaneous components	A	8.7×10^{-3}
Transformer Yard	Yard xfmers (spread to TB)	A	4.0×10^{-3}
	Yard xfmers (LOOP)	A	1.6×10^{-3}
	Yard transformers (Others)	F	1.5×10^{-2}
Plant-Wide Components	Fire protection panels	F	2.4×10^{-3}
	RPS MG sets	F	5.5×10^{-3}
	Non-qualified cable run	E	6.3×10^{-3}
	Junction in non-qualified cable	E	1.6×10^{-3}
	Junction box in qualified cable	E	1.6×10^{-3}
	Transformers	F	7.9×10^{-3}
	Battery chargers	F	4.0×10^{-3}
	Hydrogen Tanks	G	3.2×10^{-3}
	Misc. hydrogen fires	C	3.2×10^{-3}
	Gas turbines	G	3.1×10^{-2} (Note 4)
	Air compressors	F	4.7×10^{-3}
	Ventilation subsystems	F	9.5×10^{-3}
	Elevator motors	F	6.3×10^{-3}
	Dryers	F	8.7×10^{-3}
	Transients	D	1.3×10^{-3} (Note 3)
	Cable fires caused by welding	C	5.1×10^{-2} (Note 3)
	Transient fires due to welding/cutting	C	3.1×10^{-2} (Note 3)

1. Frequencies are per reactor year unless otherwise noted.
2. Fire frequencies are per fraction of ignition sources per year.
3. Fire frequency represents one event. The thirteen transient events which occurred during power operation are considered by the weighting factor.
4. Fire frequency represents an estimated 130 gas-turbine-operating years.

Table B.2.6.2 (continued) Fire Ignition Sources and Frequencies by Plant Location

Notes for Ignition Source Weighting Factor Method:

Zone specific ignition sources were determined during the initial walkdown. Normally, ignition source frequencies are estimated using methods other than direct counting, including engineering judgement. These estimates are then verified during the walkdown. Estimates should be within 25% of actual values.

A. No ignition source weighting factor is necessary.

B. Obtain the ignition source weighting factor by dividing the number of ignition sources in the fire compartment by the number in the selected location.

C. Obtain the ignition source weighting factor by calculating the inverse of the number of compartments in the locations. Exclude any areas contained in locations other than in this table.

D. Obtain the ignition source weighting factor by summing the factors for ignition sources which are allowed in the zone and divide by the number of zones in the locations in this table. For example, if cigarette smoking is prohibited do not include the cigarette smoking factor in the calculation. The factors are:

- Cigarette Smoking 2
- Extension Cord 4
- Heater 3
- Candle 1
- Overheating 2
- Hot Pipe 1

Overheating addresses errors while heating potential combustibles, e.g., battery terminal grease.

E. Obtain the ignition source weighting factor by dividing the weight (or BTUs) of cable insulation in the area by the total weight (or BTUs) of cable insulation in Appendix R fire areas, not including the fire areas in either the radwaste area or the containment. Cable insulation weights (or BTUs) are provided in Appendix R combustible loadings. (Junction boxes and splices are assumed to be distributed in proportion to the amount of cable.)

F. Obtain the ignition source weighting factor by dividing the number of ignition sources in the fire area by the total number in all the locations in this table.

G. Obtain the ignition source weighting factor by dividing the number of ignition sources in the fire area by the total number in all plant locations, include locations that were not specified in this table.

Table B.2.6.3 Prairie Island Ignition Source Frequencies by IPEEE Fire Area

AREA NUMBER	AREA DESCRIPTION	AREA SQ. FT.	FIRE LOADING BTU/FT^2	IGNITION SOURCE FREQ. (per/yr) F_1
1	Containment Unit 1	8,660	76,109	Note 3
2[B2]	Ventilation Fan Floor, Unit 1	9,570	27,544	[5.88E-3] (≈5.88E-03)[1]
3	Water Chiller Room, Unit 1	1,000	42,450	1.08E-3
4N[B67]	Fuel Handling Area	4,670	26,082	[1.18E-2] (6.08E-3)[1]
5N[B69]	Old Admin Bldg (715')	3,522	17,235	[1.9E-3] (1.71E-3)[1]
6N	Old Admin Building, HVAC Area (750')	1,540	4,052	1.03E-4
7N[B70]	Old Admin Building Office Area (735')	7,532	8,497	[2.35E-2] (1.00E-4)[1]
8N[B69,B70]	Turbine Deck (Units 1 & 2)	54,870	162	9.71E-3[1]
9N	Maintenance Shops	6,550	1,209	1.28E-3
10	Train "A" Event Monitoring Equipment Room	530	26,430	1.41E-3
11	Unit 1 Normal Swgr. & Control Rod Drive Room	2,250	13,000	2.52E-3
12	OSC Room	1,000	31,180	3.20E-4
13	Control Room	4,160	63,029	2.07E-2
14N[B69]	Working Materials Storage & Lunch Room	6,550	527	1.23E-3[1]
15	Access Control	3,060	28,039	1.59E-3
16	Train "B" Event Monitoring Equipment Room	520	46,352	1.31E-3
17	Unit 2 Normal Swgr. & Control Rod Drive Room	2,250	12,764	2.52E-3
18[B18]	Relay and Cable Spreading Rm., Unit 1 & Unit 2	4,160	404,829	[2.07E-2] (1.93E-2)[1]
19N[B18]	Computer Room	980	10,000	1.42E-3[1]
20	Unit 1 4KV Safeguards Swgr. (Bus 16)	760	103,734	2.04E-3
21N[B69]	Unit 1 4KV Normal Swgr. (Bus 13,14)	1,690	9,053	2.04E-3[1]
22	480V Safeguards Swgr. (Bus 121)	770	81,805	2.09E-3
23N[B70]	Unit 2 4KV Normal Swgr. (Bus 23, 24)	1,690	15,089	2.03E-3[1]
24N	Oil Storage Area	1,350	2.17×10^6	2.96E-3
25	Diesel Gen #1 Room	1,460	109,041	6.49E-3
26	Diesel Gen #2 Room	1,350	116,444	6.49E-3
27N[B69]	Water Conditioning Equipment Area	3,800	4,316	8.80E-4[1]
28aN	Transformer 1GT	Note 2	2,526	Note 3
28bN	Transformer 2GT	Note 2	2,526	Note 3
28cN	Transformer 1R	Note 2	1,132	Note 3
28dN	Transformer 1M	Note 2	678	Note 3
28eN	Transformer 2M	Note 2	678	Note 3

Table B.2.6.3 (continued) Prairie Island Ignition Source Frequencies by IPEEE Fire Area

AREA NUMBER	AREA DESCRIPTION	AREA SQ. FT.	FIRE LOADING BTU/FT^2	IGNITION SOURCE FREQ. (per/yr) F_1
28fN	Transformer 2RX & Y	Note 2	746	Note 3
29	Admin Building Electrical & Piping Room #1	1,100	40,091	1.90E-4
30	Admin Building Electrical & Piping Room #2	1,100	38,955	1.90E-4
31	"A" Train Hot S/D Panel & Air Compressor/AFW Room	1,180 2,360 (Note 4)	36,780	1.52E-3
32	"B" Train Hot S/D Panel & Air Compressor/AFW Room	1,180 2,360 (Note 4)	35,064	1.61E-3
33	Battery Room 11	590	19,966	1.26E-3
34	Battery Room 12	590	27,864	1.18E-3
35	Battery Room 21	590	20,305	1.22E-3
36	Battery Room 22	590	27,746	1.3E-3
37	Unit 1 480V Normal Swgr. (Bus 150, 160)	1,030	43,172	2.10E-3
38	Unit 2 480V Normal Swgr. (Bus 250, 260)	1,100	38,788	2.10E-3
39N[B67]	Radiation Waste Building	2,990	9,799	incl w/ FA04[1]
40N	Cooling Towers 121,122, 123 & 124	Note 2	Note 2	Note 3
41A	Screenhouse (DDCWP Room)	1,840	108,283	2.20E-2
41B	Screenhouse Basement	4,220	31,770	1.14E-2
41N	Screenhouse (General Area)	Note 2	Note 2	3.60E-3
42N	Cooling Tower Pump House	3,670	67.8	Note 3
43N	Unit 2 Transformer Oil Sump	Note 2	Note 2	Note 3
44N	Unit 1 Transformer Oil Sump	Note 2	Note 2	Note 3
45N	Fuel Oil and Transfer House	100	Note 2	Note 2
46N	Cooling Tower Equipment House & Transformers	1,620	42,407	Note 3
47N	Cooling Tower Transformer Oil Sump	Note 2	Note 2	Note 3
48N	D1, D2 Diesel Fuel Oil Storage Tanks	Note 2	N/A	Note 3
49N	Heating Boiler Fuel Oil Storage Tanks	Note 2	10,110	Note 3
50N	Cooling Tower Control House 121 & 122	990	Note 2	Note 3
51N	Neutralizer Tank Pump House/Warehouse #2	212.5	Note 2	Note 3
52N	Parking Lot	Note 2	Note 2	Note 3
53N	Receiving Warehouse, NPD Office & NPD Annex	Note 2	Note 2	Note 3
54N	Cooling Tower Control Hose 123 & 124	990	Note 2	Note 3
55N	Warehouse #1 and Fab Shop	Note 2	Note 2	Note 3
56N	Drum Storage Area	Note 2	Note 2	Note 3
57N[B69]	Gas House	650	11,646	3.8E-4[1]
58	Aux Building Ground Floor Unit 1	14,560	32,541	[2.93E-2] (1.03E-2)[1]
59[B59]	Aux Building Mezzanine Floor Unit 1	10,700	77,570	[9.41E-3] (8.86E-3)[1]

Table B.2.6.3 (continued) Prairie Island Ignition Source Frequencies by IPEEE Fire Area

AREA NUMBER	AREA DESCRIPTION	AREA SQ. FT.	FIRE LOADING BTU/FT^2	IGNITION SOURCE FREQ. (per/yr) F_1
60	Aux Building Operating Floor Unit 1	6,880	14,776	2.32E-3
61[B74]	Aux Bldg Anti "C" Clothing (El. 735')	6,330	15,731	[7.97E-3] (5.7E-4)[1]
61A	Aux Bldg Hatch Area (El. 755')	12,440	8,114	4.80E-4
62N[B67]	Spent Fuel Pool Area	4,180	Note 2	4.20E-4[1]
63N	Filter Room	2,430	Note 2	Note 3
64N[B67]	Aux Building Low Level Decay Area, Unit 1	830	3,133	3.20E-4[1]
65N[B67]	Spent Fuel Pool HX & Pumps	1,090	Note 2	2.00E-4[1]
66	Storage Room	1,470	Note 2	4.00E-4
67N[B67]	Resin Disposal Building	2,680	25,687	incl w/FA4[1]
68	Containment Annulus Unit 1	1,710	14,906	Note 3
69	Turbine Building Ground & Mezz Floor Unit 1	21,680	150,484	1.94E-2
70[B70]	Turbine Building Ground & Mezz Floor Unit 1	21,680	143,132	incl w/FA7[1]
71	Containment Unit 2	8,660	83,383	Note 3
72	Containment Annulus Unit 2	1,710	14,965	Note 3
73	Aux Building Ground Floor Unit 2	13,420	35,671	2.54E-2
74[B74]	Aux Building Mezz Floor Unit 2	10,700	78,215	incl w/ FA61[1]
75	Aux Building Operating Floor Unit 2	6,880	15,055	2.39E-3
76[B2]	Vent and Fan Room Unit 2	9,570	30,930	incl w/ FA2[1]
77N[B67]	Aux Building Low Level Decay Area, Unit 2	830	Note 2	2.00E-4[1]
78N[B67]	Waste Gas Compressor Area	1,510	199	1.86E-3[1]
79	480V Safeguards Swgr Room (Bus 112)	400	28,363	2.05E-3
80	480V Safeguards Swgr Room (Bus 111)	870	44,853	2.09E-3
81	4KV Safeguards Swgr Room (Bus 15)	860	45,005	2.03E-3
82	480V Safeguards Swgr Room (Bus 122)	380	25,339	2.05E-3
83N	Inst. Lab Area	1,490	1,409	4.00E-4
84N[B59,B74]	Counting Room & Labs	6,680	344	5.50E-4[1]
85N	Holdup Tank/ Demineralizer Area	4,880	Note 2	3.50E-4
86N	Intake Screenhouse, Envir Lab, Rad Monitor Station & De-Icing Pump House	Note 2	Note 2	2.21E-2
87N	Deepwell Pump House #1	110	Note 2	Note 3
88N	Deepwell Pump House #2	110	Note 2	Note 3
89N	Guardhouse	3,074 3,140 Note 5	Note 2	Note 3
90N[B70]	Emergency Generator Building	570	127,193	6.94E-3[1]
91N	Diesel Fuel Pump & Decay Cooling Water Pump Oil Storage Tanks	Note 2	N/A	Note 3
92	Water Chiller Room Unit 2	1,000	44,450	1.09E-3
93N[B67]	Drum Storage/Low Level Radwaste Warehouse	12,400	Note 2	7.00E-5[1]
94N[B69]	Service Building/ Computer Area	Note 2	Note 2	4.15E-3[1]

Table B.2.6.3 (continued) Prairie Island Ignition Source Frequencies by IPEEE Fire Area

AREA NUMBER	AREA DESCRIPTION	AREA SQ. FT.	FIRE LOADING BTU/FT^2	IGNITION SOURCE FREQ. (per/yr) F_1
95N	D5 Diesel Fuel Oil Storage Tanks	N/A Note 2	N/A Note 2	Note 3
96N	D6 Diesel Fuel Oil Storage Tanks	N/A Note 2	N/A Note 2	Note 3
97^{B101}	D5 Basement (El. 687')	2,100	97,000	[1.53E-2] (2.50E-4)[1]
98^{B102}	D6 Basement (El. 687')	2,330	97,000	[1.52E-2] (2.50E-4)[1]
99N	Stairwells (El. 695',707' & 718')	N/A Note 2	N/A Note 2	1.00E-4
100N	#21 D5/D6 Fuel Oil Receiving Tank	429	4.9×10^6	1.00E-4
101^{B101}	D5 Diesel Generator Room	1,980	86,000	1.13E-2[1]
102^{B102}	D6 Diesel Generator Room	1,980	86,000	1.13E-2[1]
103^{B101}	D5 Emergency DG Control Room	550	21,000	4.30E-4[1]
104^{B102}	D6 Emergency DG Control Room	550	20,000	4.30E-4[1]
$105N^{B101}$	D5 Battery Room	550	9,400	1.60E-4[1]
$106N^{B102}$	D6 Battery Room	550	9,100	1.60E-4[1]
107^{B101}	D5 Inverter Room	460	3,000	2.00E-4[1]
108^{B102}	D6 Inverter Room	460	4,300	2.00E-4[1]
109^{B101}	D5 Normal MCC & Cable Tray Area	1,450	56,000	8.30E-4[1]
110^{B102}	D6 Normal MCC & Cable Tray Area	1,600	48,000	9.10E-4[1]
111^{B101}	D5 Building - Mezzanine Floor 718'	440	32,000	1.70E-4[1]
112^{B102}	D6 Building - Mezzanine Floor 718'	440	33,000	1.70E-4[1]
113	#21 D5 Fuel Oil Day Tank Room	125	700,000	1.00E-4
114	#22 D6 Fuel Oil Day Tank Room	215	700,000	1.00E-4
115^{B101}	#21 D5 Lube Oil M-U Tank Room	90	1.4×10^6	Note 3
116^{B102}	#22 D6 Lube Oil M-U Tank Room	90	1.4×10^6	Note 3
117^{B101}	4KV Bus 25; MCC-2TA1	1,480	51,000	2.03E-3[1]
118^{B102}	4KV Bus 26; MCC-2TA2	1,400	42,000	2.03E-3[1]
119	#21 D5 Ht/Lt M-U Tank Pump Room	510	9,300	2.80E-4
120	#22 D6 Ht/Lt M-V Tank Pump Room	510	9,300	2.80E-4
121N	Stairwell (El. 735')	402	N/A	Note 3
122^{B102}	480V Bus 221/222 Room	1,650	15,400	2.13E-3[1]
123^{B101}	D5 Radiator Room	1,280	8,200	1.70E-4[1]
124^{B102}	D6 Radiator Room	1,280	8,500	1.70E-4
125	D5 Fan Room	1,280	N/A Note 2	3.40E-4
126	D6 Fan Room	1,280	N/A Note 2	3.40E-4
127^{B101}	480V Bus 211/212 Room	1,480	17,600	2.13E-3[1]
128N	4KV Bus 27 Room	224	*	2.07E-4

Table B.2.6.3 (continued) Prairie Island Ignition Source Frequencies by IPEEE Fire Area

AREA NUMBER	AREA DESCRIPTION	AREA SQ. FT.	FIRE LOADING BTU/FT2	IGNITION SOURCE FREQ. (per/yr) F_1
129N	D5 Radiator Exhaust (Roof)	1,280	N/A Note 2	1.00E-4
130N	D6 Radiator Exhaust (Roof)	1,280	N/A Note 2	1.00E-4
131N	New Admin Building	Note 2	Note 2	Note 3

Notes:

1 For burn sequences, the first area within a sequence shows the *sequence* frequency in brackets [ ]. The area-specific frequency for the first area within a sequence is shown in parenthese ( ). For all other areas within a sequence, the table shows the frequency of that specific area. The frequencies of all areas within a sequence, when added together, equal the burn sequence frequency. Note that some area-specific frequencies are negligible (see Note 3), or bundled with another area within the sequence.

2 Entires in columns labeled Area Sq. Ft. and Fire Loading are taken directly from Prairie Island Fire Hazards Analysis (F.5, App. F), Table 6-2. Blanks or "N/A" or "*" in any of these columns are found in that table, and indicate that the Fire Hazards Analysis concluded that a fire in the area has no effect on plant shutdown; no safe shutdown equipment is located in the area. In some cases, the IPEEE has conservatively assigned a fire frequency to the area based upon the FIVE methodology. However, the analysis indicates that even with this conservative assumption the area does not contribute.

3 The frequency for this area is negligible, or has not been estimated because fires will not affect the ability to shutdown the plant (see also Note 2).

4 Loading based on 1180 sq. ft. for oil, 2360 sq. ft. for cable; total BTU value based on *total* sq. ft. for fire area.

5 First entry is ground level, second is basement level.

B2 Burn sequence B2 includes Fire Areas 02 and 76.

B18 Burn sequence B18 includes Fire Areas 18 and 19.

B58 Burn sequence B58 includes Fire Areas 58, 73. However, this burn sequence is qualitatively dismissed (see discussion for Fire Area 58), and individual analyses are performed for Fire Area 58 and 73 using the fire initiating frequencies provided in this table for those areas.

B59 Burn sequence B59 includes Fire Areas 59 and 84.

B67 Burn sequence B67 includes Fire Areas 04, 39, 62, 64, 65, 67, 77, 78, 85 and 93.

B69 Burn sequence B69 includes Fire Areas 05, 08, 14, 21, 27, 57 and 94.

B70 Burn sequence B70 includes Fire Areas 07, 08, 23, 70 and 90.

B74 Burn sequence B74 includes Fire Areas 61, 74 and 84.

B101 Burn sequence B101 includes Fire Areas 97, 101, 103, 105, 107, 109, 111, 117, 123 and 127.

B102 Burn sequence B102 includes Fire Areas 98, 102, 104, 106, 108, 110, 112, 118, 122 and 124.

B.2.7 Fire Area Initial Screening

A fire in the plant involving equipment that may be required to support plant operation was assumed to result in a plant shutdown. Therefore, only fire areas outside the main reactor/turbine building complex were screened from further evaluation in this step. The results of the qualitative screening process are shown in Table B.2.7.1.

B.2.8 Fire Detection and Suppression

This section discusses automatic detection and automatic or manual fire suppression at Prairie Island. The detection and suppression systems available in each fire area are presented in the Prairie Island Updated Fire Hazards Analysis [7] and listed in Table B.2.8.1.

While detection and suppression capability are discussed for most areas of the plant, it should be noted that the only locations where detection and/or suppression were credited in the accident sequence quantification were the Control Room, Relay Room, and the AFW pump rooms.

B.2.8.1 Detection

Several methods of automatic fire detection are used at Prairie Island. These methods are ionization detection, thermal detection, smoke and flame detection. Alarms are designed to sound locally (halon- and cardox-protected areas) and in the Control Room. The detection system will also sound an alarm if there is a failure in the detector system.

In addition to the alarms described above, there are heat-actuated device alarms and/or water flow alarms associated with water suppression systems which alarm in the Control Room.

B.2.8.2 Automatic Suppression

The automatic suppression systems at Prairie Island consist of water, CO_2 and Halon based systems. Two 100% redundant, 2000 gpm, fire pumps supply water to the Fire Protection System; one is electrically powered and the other diesel engine powered. A third 2000 gpm pump, also electrically powered and normally used as a screenwash pump, may also be used as a backup pump for the Fire Protection System. The water delivery portion of the system consists of automatic pre-action, deluge, wet/dry pipe sprinklers and hose stations.

Although several locations in the plant are protected by automatic fire suppression systems, the Relay Room and the AFW pump rooms are the only locations in which this analysis takes credit for the automatic suppression of a fire. The Relay Room is protected by a 6-ton carbon dioxide system with alarm sirens and a sixty-second delay. A detection system and a thermal actuation system is provided. Ionization detectors provide an early warning alarm to the Control Room. The auto action mode is normally bypassed when the room is occupied; however, the carbon dioxide system may be manually actuated at any time. The room, however, is not routinely occupied and the auto mode is therefore normally on. The carbon dioxide system is backed up by manual hose stations and extinguishers. The unavailability of the CO_2 system used in the

quantification of this fire scenario is taken from the FIVE methodology. This generic CO_2 system unavailability is 4E-2.

The AFW pump rooms (Areas 31 and 32) contain ionizing detection systems and thermal actuators. Fire sprinklers are located throughout the areas. Manual hose stations and extinguishers serve as back-up devices.

Table B.2.7.1 Summary of Prairie Island IPEEE Area Screening

AREA NUMBER	AREA DESCRIPTION	QUALITATIVELY SCREENED	RETAINED FOR FURTHER EVALUATION
1	Containment Unit 1	X*	
2	Ventilation Fan Floor, Unit 1		X
3	Water Chiller Room, Unit 1		X
4N	Fuel Handling Area		X
5N	Old Admin Bldg (715')	X	
6N	Old Admin Building, HVAC Area (750')	X	
7N	Old Admin Building Office Area (735')	X	
8N	Turbine Deck (Units 1 & 2)	X	
9N	Maintenance Shops	X	
10	Train "A" Event Monitoring Equipment Room		X
11	Unit 1 Normal Swgr. & Control Rod Drive Room		X
12	OSC Room	X	
13	Control Room		X
14N	Working Materials Storage & Lunch Room	X	
15	Access Control		X
16	Train "B" Event Monitoring Equipment Room		X
17	Unit 2 Normal Swgr. & Control Rod Drive Room		X
18	Relay and Cable Spreading Rm., Unit 1 & Unit 2		X
19N	Computer Room	X	
20	Unit 1 4KV Safeguards Swgr. (Bus 16)		X
21N	Unit 1 4KV Normal Swgr. (Bus 13, 14)		X
22	480V Safeguards Swgr. (Bus 121)		X
23N	Unit 2 4KV Normal Swgr. (Bus 23, 24)		X
24N	Oil Storage Area	X	
25	Diesel Gen #1 Room		X
26	Diesel Gen #2 Room		X
27N	Water Conditioning Equipment Area		X
28aN	Transformer 1GT		X
28bN	Transformer 2GT		X
28cN	Transformer 1R		X
28dN	Transformer 1M		X
28eN	Transformer 2M		X
28fN	Transformer 2RX & Y		X
29	Admin Building Electrical & Piping Room #1		X
30	Admin Building Electrical & Piping Room #2		X
31	"A" Train Hot S/D Panel & Air Comp/AFW Rm		X
32	"B" Train Hot S/D Panel & Air Comp/AFW Rm		X
33	Battery Room 11		X
34	Battery Room 12		X
35	Battery Room 21		X
36	Battery Room 22		X
37	Unit 1 480V Normal Swgr. (Bus 150, 160)		X
38	Unit 2 480V Normal Swgr. (Bus 250, 260)		X
39N	Radiation Waste Building	X	
40N	Cooling Towers 121,122, 123, 124	X	
41A	Screenhouse (DDCWP Room)		X
41B	Screenhouse Basement		X

Table B.2.7.1 (continued) Summary of Prairie Island IPEEE Area Screening

AREA NUMBER	AREA DESCRIPTION	QUALITATIVELY SCREENED	RETAINED FOR FURTHER EVALUATION
41N	Screenhouse (General Area)		X
42N	Cooling Tower Pump House	X	
43N	Unit 2 Transformer Oil Sump	X	
44N	Unit 1 Transformer Oil Sump	X	
45N	Fuel Oil and Transfer House	X	
46N	Cooling Tower Equipment House & Transformers	X	
47N	Cooling Tower Transformer Oil Sump	X	
48N	D1, D2 Diesel Fuel Oil Storage Tanks	X	
49N	Heating Boiler Fuel Oil Storage Tanks	X	
50N	Cooling Tower Control House 121 & 122	X	
51N	Neutralizer Tank Pump House/ Warehouse #2	X	
52N	Parking Lot	X	
53N	Receiving Warehouse, NPD Office & NPD Annex	X	
54N	Cooling Tower Control Hose 123 & 124	X	
55N	Warehouse #1 and Fab Shop	X	
56N	Drum Storage Area	X	
57N	Gas House	X	
58	Aux Building Ground Floor Unit 1		X
59	Aux Building Mezzanine Floor Unit 1		X
60	Aux Building Operating Floor Unit 1		X
61	Aux Bldg Anti "C" Clothing (735')		X
61A	Aux Bldg Hatch Area (755')		X
62N	Spent Fuel Pool Area	X	
63N	Filter Room	X	
64N	Aux Building Low Level Decay Area, Unit 1	X	
65N	Spent Fuel Pool HX & Pumps	X	
66	Storage Room	X	
67N	Resin Disposal Building	X	
68	Containment Annulus Unit 1	X*	
69	Turbine Building Ground & Mezz Floor Unit 1		X
70	Turbine Building Ground & Mezz Floor Unit 2		X
71	Containment Unit 2	X*	
72	Containment Annulus Unit 2	X*	
73	Aux Building Ground Floor Unit 2		X
74	Aux Building Mezz Floor Unit 2		X
75	Aux Building Operating Floor Unit 2		X
76	Vent and Fan Room Unit 2		X
77N	Aux Building Low Level Decay Area, Unit 2	X	
78N	Waste Gas Compressor Area	X	
79	480V Safeguards Swgr Room (Bus 112)		X
80	480V Safeguards Swgr Room (Bus 111)		X
81	4KV Safeguards Swgr Room (Bus 15)		X
82	480V Safeguards Swgr Room (Bus 122)		X
83N	Inst. Lab Area	X	
84N	Counting Room & Labs	X	
85N	Holdup Tank/ Demineralizer Area		X
86N	Intake Screenhouse, Envir Lab, Rad Monitor Station & De-Icing Pump House		X
87N	Deepwell Pump House #1	X	

Table B.2.7.1 (continued) **Summary of Prairie Island IPEEE Area Screening**

AREA NUMBER	AREA DESCRIPTION	QUALITATIVELY SCREENED	RETAINED FOR FURTHER EVALUATION
88N	Deepwell Pump House #2	X	
89N	Guardhouse	X	
90N	Emergency Generator Building	X	
91N	Diesel Fire Pump & Diesel Cooling Water Pump Oil Storage Tanks	X	
92	Water Chiller Room Unit 2		X
93N	Drum Storage/Low Level Radwaste Warehouse	X	
94N	Service Building/ Computer Area	X	
95N	D5 Diesel Fuel Oil Storage Tanks	X	
96N	D6 Diesel Fuel Oil Storage Tanks	X	
97	D5 Basement (687')		X
98	D6 Basement (687')		X
99N	Stairwells (El. 695',707' & 718')	X	
100N	#21 D5/D6 Fuel Oil Receiving Tank	X	
101	D5 Diesel Generator Room		X
102	D6 Diesel Generator Room		X
103	D5 Emergency Diesel Generator Control Room		X
104	D6 Emergency Diesel Generator Control Room		X
105N	D5 Battery Room		X
106N	D6 Battery Room		X
107	D5 Inverter Room		X
108	D6 Inverter Room		X
109	D5 Normal MCC & Cable Tray Area		X
110	D6 Normal MCC & Cable Tray Area		X
111	D5 Building - Mezzanine Floor 718'		X
112	D6 Building - Mezzanine Floor 718'		X
113	#21 D5 Fuel Oil Day Tank Room		X
114	#22 D6 Fuel Oil Day Tank Room		X
115	#21 D5 Lube Oil M-U Tank Room		X
116	#22 D6 Lube Oil M-U Tank Room		X
117	4KV Bus 25; MCC-2TA1		X
118	4KV Bus 26; MCC-2TA2		X
119	#21 D5 Ht/Lt M-U Tank Pump Room		X
120	#22 D6 Ht/Lt M-V Tank Pump Room		X
121N	Stairwell (El. 735')		X
122	480V Bus 221/222 Room		X
123	D5 Radiator Room		X
124	D6 Radiator Room		X
125	D5 Fan Room		X
126	D6 Fan Room		X
127	480V Bus 211/212 Room		X
128N	4KV Bus 27 Room		X
129N	D5 Radiator Exhaust (Roof)	X	
130N	D6 Radiator Exhaust (Roof)	X	
131N	New Admin Building	X	

* A significant fire in the containment is not likely given its combustible loading and physical configuration. Much of the combustible material located in the containment is lube oil for the reactor coolant pumps. This oil is normally contained. In addition, an oil collecting system that collects the oil in the event of a spill is also installed. The remaining combustible material,

Table B.2.7.1 (continued) Summary of Prairie Island IPEEE Area Screening

electrical cable, located in these areas are fire retardant (IEEE-383 rated). Because of these factors, a significant fire within the containment is not expected to occur. The FIVE methodology recognizes the unlikely occurrence of a containment fire and does not even provide an ignition source frequency for this area.

B.2.8.3 Manual Suppression

Each plant is required to maintain a manual fire fighting capability. The fire brigades developed under these requirements are well trained and capable of fighting fires while awaiting support from professional fire fighting teams, if called. To take credit for brigade or other manually actuated suppression system response in the FIVE methodology, however, the plant must demonstrate that the fire brigade can assemble, fight, and control a fire in the compartment before the fire causes damage to safe shutdown equipment. That is, the time to detect a fire plus the time to respond to the scene with equipment and control the fire must be less than the time required for fire to damage critical equipment.

Detection time is dependent upon the type of detection equipment in a compartment. Ionization detectors should detect a fire during the incipient stages, whereas heat detectors would not be expected to detect a fire until the fire is more fully involved. Fire brigade response time includes time to verify the detection and the time for the team to respond to the scene with equipment. Response time is obviously highly variable and is dependent upon the location of the fire, location of the brigade members at the time of the event and many other factors.

The FIVE methodology assigns a probability of successfully suppressing a fire manually if and only if the following two criteria can be met:

1. The plant can demonstrate that detection and manual response can occur before damage to safe shutdown equipment, and

2. Fire brigade effectiveness can be demonstrated per the requirements of the NUREG/CR-5088 "Fire Risk Scoping Study" [11].

The FIVE methodology states that the probability of manually suppressing a fire should not be greater than 0.9.

For the purpose of this analysis, no credit for manual suppression was taken before damage of safe shutdown equipment is assumed to occur. For example, manual suppression is assumed for Control Room fires, but only after the fire has disabled the safe shutdown equipment. This analysis recognizes that manual suppression efforts will be taken to suppress a fire and to ensure that the fire does not propagate outside the fire area boundaries. Manual fire suppression equipment is available throughout the plant in the form of portable fire extinguishers and hose stations. The fire fighting training program in place at Prairie Island ensures that fire brigade members are adequately trained to effectively use this equipment. The limited credit assumed for manual suppression of fires in the Prairie Island fire IPEEE is for accident sequence quantification purposes only, and is very conservative.

Following successful suppression in the Control Room or Relay Room, some equipment was assumed to be lost (see Section B.2.10.1). If the fire started in a cabinet or panel, all the circuits in that cabinet/panel was assumed failed by the fire. Since suppression was not credited except in these limited areas, suppression-induced damage outside of these areas is not an issue.

In the Control Room, fire detection can be accomplished in a variety of ways:

- The Control Room contains local smoke detectors in the ceiling which would provide an audible alarm should smoke be generated in the Control Room.
- The Control Room is continuously staffed and a fire should be quickly sensed by smell or by sight by the operators.

It is assumed that the failure to detect a fire in the control cabinets is negligibly small due to the redundancy and diversity of cues and due to the continuous staffing of the Control Room. It is further assumed that fire suppression efforts would be initiated immediately upon detection of a fire because of the continuous staffing of the Control Room. The FIVE methodology allows a minimum value of 0.1 for the probability of failing to suppress a fire manually in a given space even if unoccupied. This analysis assumes additional credit in the likelihood of successfully suppressing a Control Room fire for the following reasons:

- The Control Room is continuously staffed. In addition, Control Room operators are trained in fire suppression techniques. Therefore, early detection and action to suppress a fire is very likely.
- The cabinets contain relatively small amounts of combustible material.

For these reasons, a probability of 0.01 is assigned to failing to manually suppress a fire in the Control Room.

Table B.2.8.1 Fire Detection and Suppression

AREA NUMBER	AREA DESCRIPTION	DETECTION	FIRE PROTECTION AUTO.	FIRE PROTECTION MAN.
1	Containment Unit 1	ION	None	Hose Station, Fire Extg.
2	Ventilation Fan Floor, Unit 1	ION	FWP	Hose Station, Fire Extg.
3	Water Chiller Room, Unit 1	ION	None	OSRM
4N	Fuel Handling Area	ION	SWP-1	Hose Station, Fire Extg.
5N	Old Admin Bldg (715')	ION	WPS-29	Extg., OSRM
6N	Old Admin Bldg, HVAC Area (750')	ION	None	Extg., OSRM
7N	Old Admin Bldg Office Area (735')	ION	None	Extg., Hyd., OSRM
8N	Turbine Deck (Units 1 & 2)	N/A	WPS-30	Extg.,DM, Hose Station
9N	Maintenance Shops	ION	SWP-6	Extg., OSRM
10	Train "A" Event Monitoring Equipment Room	ION	None	Extg., OSRM
11	Unit 1 Normal Swgr. & Control Rod Drive Room	ION	None	Extg., OSRM
12	OSC Room	ION	WPS-23	Extg., OSRM
13	Control Room	ION	None	Extg., OSRM
14N	Working Materials Storage/Lunch Room	ION	WPS-25	Hose Station, Extg.
15	Access Control	ION	WPS-20	Hose Station, Extg.
16	Train "B" Event Monitoring Equipment Room	ION	None	Extg., OSRM
17	Unit 2 Normal Swgr. & Control Rod Drive Room	ION	None	Extg., OSRM
18	Relay and Cable Spreading Rm., Unit 1 & Unit 2	ION	CO_2	OSRM
19N	Computer Room	ION	CO_2	Extg., OSRM
20	Unit 1 4KV Safeguards Swgr. (Bus 16)	ION	None	Extg., OSRM
21N	Unit 1 4KV Normal Swgr. (Bus 13, 14)	ION	None	Extg., OSRM
22	480V Safeguards Swgr. (Bus 121)	ION	None	Extg., OSRM
23N	Unit 2 4KV Normal Swgr. (Bus 23, 24)	ION	None	Extg., OSRM
24N	Oil Storage Area	FLAME, HEAT	DA-2	OSRM
25	Diesel Gen #1 Room	ION, FLAME	PA-1	Extg., OSRM
26	Diesel Gen #2 Room	ION, HEAT	PA-1	OSRM
27N	Water Conditioning Equipment Area	ION	WPS-9 Deluge	Hose Station, Extg.
28aN	Transformer 1GT	Thermal	Deluge	Hyd., DM-1
28bN	Transformer 2GT	Thermal	Deluge	Hyd., DM-5
28cN	Transformer 1R	Thermal	Deluge	Hyd., DM-3
28dN	Transformer 1M	Thermal	Deluge	Hyd., DM-2
28eN	Transformer 2M	Thermal	Deluge	Hyd., DM-4
28fN	Transformer 2RX & Y	Thermal	Deluge	Hyd., DM-6
29	Admin Building Electrical & Piping Room #1	ION	None	Extg., OSRM
30	Admin Building Electrical & Piping Room #2	ION	None	OSRM
31	"A" Train Hot S/D Panel & Air Compressor/AFW Rm	ION, THERMAL	WPS-10	Extg., OSRM
32	"B" Train Hot S/D Panel & Air Compressor/AFW Rm	ION, THERMAL	WPS-10	Extg., OSRM
33	Battery Room 11	ION	None	OSRM
34	Battery Room 12	ION	None	OSRM
35	Battery Room 21	ION	None	OSRM
36	Battery Room 22	ION	None	OSRM
37	Unit 1 480V Normal Swgr. (Bus 150, 160)	ION	None	Extg., OSRM
38	Unit 2 480V Normal Swgr. (Bus 250, 260)	ION	None	Extg., OSRM
39N	Radiation Waste Building	ION	None	Hose Station, Extg.
40N	Cooling Towers 121,122, 123, 124	N/A	None	Hyd.
41A	Screenhouse (DDCWP Room)	ION	PA-9	Hose Station, Extg.
41B	Screenhouse Basement	ION	PA-9	Hose Station, Extg.
41N	Screenhouse (General Area)	ION	PA-9	Hose Station, Extg.
42N	Cooling Tower Pump House	ION	None	Extg., Hyd.
43N	Unit 2 Transformer Oil Sump	N/A	None	Hyd.
44N	Unit 1 Transformer Oil Sump	N/A	None	Hyd.

Table B.2.8.1 (continued) Fire Detection and Suppression

AREA NUMBER	AREA DESCRIPTION	DETECTION	FIRE PROTECTION	
45N	Fuel Oil and Transfer House	ION	None	Extg., Hyd.
46N	Cooling Tower Equipment House & Transformers	ION	None	Extg., Hyd.
47N	Cooling Tower Transformer Oil Sump	N/A	None	Hyd.
48N	D1, D2 Diesel Fuel Oil Storage Tanks	N/A	None	Hyd.
49N	Heating Boiler Fuel Oil Storage Tank	N/A	None	Hyd.
50N	Cooling Tower Control House 121 & 122	ION	None	Extg., Hyd.
51N	Neutralizer Tank Pump House/ Warehouse #2	ION	DE-3	Extg., Hyd.
52N	Parking Lot	N/A	None	Extg., Hyd.
53N	Receiving Wa.ehouse, NPD Office & NPD Annex	ION	DPS-1 PA-10	Extg., Hyd., Hose Station
54N	Cooling Tower Control House 123 & 124	ION	None	Extg., Hyd.
55N	Warehouse #1 and Fab Shop	ION	WPS-26	Extg., Hose Station
56N	Drum Storage Area	N/A	None	DM-7, Hyd., Extg.
57N	Gas House	THERMAL	None	Extg., Hyd.
58	Aux Building Ground Floor Unit 1	ION, SMOKE, THERMAL	WPS-11 SWP-2,4	Extg. Hose Station
59	Aux Building Mezzanine Floor Unit 1	ION	SWP-4&2 WPS-19, 20,23,24	Extg. Hose Station
60	Aux Building Operating Floor Unit 1	ION	SWP-2&4 WPS-24	Extg. Hose Station
61	Aux Bldg Anti "C" Clothing (735')	ION	WPS-27 WPS-28	Extg. Hose Station
61A	Aux Bldg Hatch Area (755')	ION		
62N	Spent Fuel Pool Area	ION	None	Extg., Hose Station
63N	Filter Room	N/A	None	OSRM
64N	Aux Building Low Level Decay Area, Unit 1	ION	None	OSRM
65N	Spent Fuel Pool HX & Pumps	N/A	None	OSRM
66	Storage Room	ION	WPS-22	OSRM
67N	Resin Disposal Building	ION	None	Extg., Hose Station
68	Containment Annulus Unit 1	ION, FLAME	PA-3, 4	OSRM
69	Turbine Building Ground & Mezz Floor Unit 1	ION, HEAT, SMOKE	DA-1&3 WPS-7,8,9,18 SWP-3,5	Extg. Hose Station
70	Turbine Building Ground & Mezz Floor Unit 2	ION	DA-4&5 WPS-15,16, 17,21 SWP-13,14	Extg. Hose Station
71	Containment Unit 2	ION, SMOKE	None	Extg., Hose Station
72	Containment Annulus Unit 2	ION, FLAME	PA-6&7	OSRM
73	Aux Building Ground Floor Unit 2	ION, SMOKE	SWP-12	Extg., Hose Station
74	Aux Building Mezz Floor Unit 2	ION	SWP-12	Extg., Hose Station
75	Aux Building Operating Floor Unit 2	ION	SWP-12	Extg., Hose Station
76	Vent and Fan Room Unit 2	ION	FWP	Extg., Hose Station
77N	Aux Building Low Level Decay Area, Unit 2	N/A	None	None
78N	Waste Gas Compressor Area	ION	None	OSRM
79	480V Safeguards Swgr Rm (Bus 112)	ION	None	Extg., OSRM
80	480V Safeguards Swgr Rm (Bus 111)	ION	None	Extg., OSRM
81	4KV Safeguards Swgr Room (Bus 15)	ION	None	Extg., OSRM
82	480V Safeguards Swgr Rm (Bus 122)	ION	None	Extg., OSRM
83N	Inst. Lab Area	ION	None	Extg., OSRM
84N	Counting Room & Labs	ION	None	Extg., OSRM
85N	Holdup Tank/ Demineralizer Area	ION	None	OSRM
86N	Intake Screenhouse, Envir Lab, Rad Monitor Station & De-Icing Pump House	N/A	None	Extg., Hyd.
87N	Deepwell Pump House #1	ION	None	Extg.
88N	Deepwell Pump House #2	ION	None	Extg.
89N	Guardhouse	ION	DE-1	Extg., (H)
90N	Emergency Generator Building	ION	DE-2	Extg., Hyd.
91N	Diesel Fire Pump & Diesel Cooling Water Pump Oil Storage Tanks	N/A	None	Hyd.

Table B.2.8.1 (continued) Fire Detection and Suppression

AREA NUMBER	AREA DESCRIPTION	DETECTION	FIRE PROTECTION	
92	Water Chiller Room Unit 2	ION	None	OSRM
93N	Drum Storage/Low Level Radwaste Warehouse	ION	DM-7	Extg., Hyd.
94N	Service Building/ Computer Area	ION	Halon, DPS-2 SWP-31	Extg. Hyd.
95N	D5 Diesel Fuel Oil Storage Tanks	N/A	None	Hyd.
96N	D6 Diesel Fuel Oil Storage Tanks	N/A	None	Hyd.
97	D5 Basement (687')	ION	PAD-12	Extg., OSRM
98	D6 Basement (687')	ION	PAD-13	Extg., OSRM
99N	Stairwells (El. 695',707' & 718')	N/A	WPS-32	Extg., OSRM
100N	#21 D5/D6 Fuel Oil Receiving Tank	ION	DA-6	Extg., OSRM
101	D5 Diesel Generator Room	THERMAL, FLAME	PAD-12	Extg., OSRM
102	D6 Diesel Generator Room	THERMAL, FLAME	PAD-13	Extg., OSRM
103	D5 Emergency Diesel Generator Control Room	ION	None	Extg., OSRM
104	D6 Emergency Diesel Generator Control Room	ION	None	Extg., OSRM
105N	D5 Battery Room	ION	None	Extg., OSRM
106N	D6 Battery Room	ION	None	Extg., OSRM
107	D5 Inverter Room	ION	None	Extg., OSRM
108	D6 Inverter Room	ION	None	Extg., OSRM
109	D5 Normal MCC & Cable Tray Area	ION	None	Extg., OSRM
110	D6 Normal MCC & Cable Tray Area	ION	None	Extg., OSRM
111	D5 Building - Mezzanine Floor 718'	ION	None	Extg., OSRM
112	D6 Building - Mezzanine Floor 718'	ION	None	Extg., OSRM
113	#21 D5 Fuel Oil Day Tank Room	ION	WPS-32	Extg., OSRM
114	#22 D6 Fuel Oil Day Tank Room	ION	WPS-33	Extg., OSRM
115	#21 D5 Lube Oil M-U Tank Room	ION	WPS-32	Extg., OSRM
116	#22 D6 Lube Oil M-U Tank Room	ION	WPS-33	Extg., OSRM
117	4KV Bus 25; MCC-2TA1	ION	None	Extg., OSRM
118	4KV Bus 26; MCC-2TA2	ION	None	Extg., OSRM
119	#21 D5 Ht/Lt M-U Tank Pump Room	ION	None	Extg., OSRM
120	#22 D6 Ht/Lt M-V Tank Pump Room	ION	None	Extg., OSRM
121N	Stairwell (El. 735')	ION	None	Extg., OSRM
122	480V Bus 221/222 Room	ION	None	Extg., OSRM
123	D5 Radiator Room	N/A	None	Extg., OSRM
124	D6 Radiator Room	N/A	None	Extg., OSRM
125	D5 Fan Room	N/A	None	Extg., OSRM
126	D6 Fan Room	N/A	None	Extg., OSRM
127	480V Bus 211/212 Room	ION	None	Extg., OSRM
128N	4KV Bus 27 Room	ION	None	Extg., OSRM
129N	D5 Radiator Exhaust (Roof)	N/A	None	Extg., OSRM
130N	D6 Radiator Exhaust (Roof)	N/A	None	Extg., OSRM
131N	New Admin Building	N/A	PAD-10 & 11	Extg., OSRM

B.2.9 Fire Growth and Propagation

All potential propagation paths that could result in fire spreading to a compartment containing safe shutdown equipment or plant trip initiators were considered. The Appendix R fire areas were reviewed to assess the potential for cross-area propagation based on the existing fire barriers and fire area loading.

The potential for fire spread from the compartment being evaluated (exposing compartment) to the adjacent compartments (exposed compartments) was examined. Each common boundary was analyzed for fire spread in either direction. A means of addressing fire spread across these boundaries is addressed in the FIVE methodology and was used in this study. Criteria to determine fire spread were identified in Section B.2.1.

Any scenario where a fire could potentially involve two or more adjacent areas was analyzed for potential fire spread by extending unscreened boundaries. This step was performed in accordance with the FIVE screening criteria shown in Section B.2.1. Fire spread scenarios were identified and tracked for all entered fire areas.

Fire scenarios that have the potential to spread beyond the initiating compartment were identified as Burn Sequences in Table B.2.6.3. There are nine locations within the plant that have the potential for fire spread beyond the originating compartment. Fires in compartments not shown in this table will not spread to adjoining compartments.

B.2.10 Fire Event Trees

This analysis was based upon the Prairie Island transient and small LOCA event trees (Figures B.2.10-1 and B.2.10-2). A fire in most locations in the Prairie Island plant would initiate an event similar to a transient event with one or more of the systems identified in Section B.2.1 out of service due to the fire. The small LOCA event tree from the internal events PRA was used to model RCP seal LOCA. A top event was added to the diagram for operator cooldown and depressurization on the seal LOCA, although this was not credited in the quantification (see Section B.2.10.1). One additional event tree was developed specifically for this analysis (Figure B.2.10-3). It was developed for fires in the main Control and Relay rooms and was based on the internal events PRA transient event tree. Top events were added to account for the effects of suppression and switching control of the plant to the HSDPs (Hot Shutdown Panels).

Accident classes were defined such that core damage sequences with similar characteristics (e.g., reactor vessel failure pressure, core damage timing, system failures) could be grouped and analyzed together. The three accident classes employed in the fire IPEEE are a subset of the accident classes found in the internal events PRA. These accident classes are Class TEH - early core melt with the reactor at high pressure; Class TLH - late core melt at high pressure; and Class SEH - early core melt at high pressure in conjunction with a small LOCA. This is discussed in more detail in Section B.2.10.4.

B.2.10.1 Fire Event Tree Top Event Definitions

FIRE — Fire Initiator

The fire is defined as starting in a location that would cause a plant transient initiator, require a manual shutdown, or affect plant equipment potentially useful for plant shutdown.

S — Subcriticality

Insertion of negative reactivity to bring the reactor subcritical.

SUP — Suppression of Fire Before Spread (Control/Relay Rooms only, see Section B.2.10.2)

The fire is suppressed by either occupants in the room or by automatic suppression equipment before it can spread to other locations. In the Control Room fire, successful manual suppression limits the extent of the fire to the cabinet in which it is assumed to initiate (initially assumed to be the FW/AFW panel as they are located in the same panel, and loss of secondary side cooling was judged to be conservative). Successful suppression of a fire in the Relay Room assumes that fire damage occurs to FW and AFW but is limited to those systems. It is assumed that the smoke created from a fire involving one panel, given the existing ventilation, would not force the evacuation of the Control Room. In the event of fire suppression failure in the Control Room or Relay Room, it is assumed that extensive damage is possible, requiring inventory makeup to be accomplished from the HSDPs. Controls for the AFW pumps and charging pumps are located on the HSDPs.

Automatic fire suppression was also credited for fires in the AFW pump room areas. However, this credit was applied after the sequence quantification, such that the quantification of those rooms followed the transient event tree (see Section B.2.10.3).

HSDP — Operators Control Plant at Hot Shutdown Panel (HSDP) (Control/Relay Rooms only)

The operators carry out the "Control Room Evacuation (Fire)" procedure, Plant Safety Procedures, F5 Appendix B, evacuating the main Control Room (immediate actions) and transferring plant control to the HSDPs.

RCP — RCP Seal LOCA

Loss of all cooling to the RCP seals is assumed to fail the seals and result in a small LOCA. Failure of both the component cooling and charging systems will yield this condition.

H — Secondary Cooling

Two systems, auxiliary feedwater and main feedwater, are credited with providing secondary makeup under this event tree heading. Auxiliary feedwater can be provided to either or both steam generators from one of three pumps, a motor or turbine driven pump from the unit in which the trip occurred, or a motor driven pump from the second unit if operator action to align it is successful. The main feedwater pumps (two) are motor driven and, if tripped (but not failed) as a result of the initiator, can be returned to service from the Control Room.

STI <u>Short Term RCS Inventory (Bleed and Feed)</u>

For transient initiated events (typical fire events), no short term inventory makeup is required provided secondary heat removal has been successful. Bleed and feed requires manual start of at least one safety injection pump and opening of a pressurizer PORV to provide short term RCS inventory control and to remove RCS decay heat.

Given a RCP seal LOCA, a safety injection signal will be generated on low pressurizer pressure or high containment pressure and the SI pumps will start automatically. If secondary heat removal has been successful, injection by a single SI pump is all that is required to satisfy short term RCS inventory control.

CD <u>RCS Cooldown and Depressurization</u>

For RCP seal LOCA events in which high head injection through the SI pumps is not available, it is possible that the rate of loss of inventory through the break is much less than would be expected for a "random" small LOCA event. This would allow time for operator action to cooldown and depressurize the primary system such that RHR could be used for inventory control. This heading was included in the event tree to illustrate this possibility; however, no credit was taken for cooldown and depressurization in the analysis (failure of CD set to 1.0).

LTI <u>Long Term RCS Inventory</u>

For transient initiated events (typical fire events) in which secondary cooling failed but bleed and feed was successful, approximately 8 to 10 hours are available prior to depletion of the RWST. To continue adequate core cooling, initiation of recirculation from the containment sump is required. High head recirculation requires realignment of an RHR pump suction from the RWST to the containment sump and then to the suction of a SI pump, "piggy backing" the two systems.

Success criteria for long term inventory control for small LOCA sequences (e.g., RCP seal LOCA) in which secondary cooling is not available is the same as for the transient events in which bleed and feed occurs.

C <u>Containment</u>

Containment heat removal is assumed to be necessary for any accident sequence in which long term recirculation from the sump is occurring. Containment pressure control can be provided by operation of two fan coil units or a train of containment spray. Similar to SI, spray recirculation requires the containment spray pump suction to be aligned to RHR after the suction from the RHR pumps has been shifted to the containment sump.

B.2.10.2 Event Tree For Fire in Main Control Room and Relay Room

The Control Room and Relay Room fires are discussed separately due to credit taken for fire suppression in these rooms. Figure

Control Room

The event tree for fire in the main Control Room is similar to the transient event tree. The differences are:

1. The event SUP is included to account for the likelihood of the fire being suppressed by the operators before it can spread from a single Control Room panel. This event was discussed in Section B.2.8. The probability assigned to the failure of this event is 0.01.

2. The event HSDP is included to account for the operators' ability to recognize the need to evacuate the Control Room and to successfully transfer control of the plant to the HSDPs and control the plant from that location. A human reliability analysis was performed on this action. The probability of failure of this event is 3.4E-3, given at least thirty minutes to staff the HSDP.

This event tree assumes that successful suppression of the fire in the Control Room must take place before it can spread to other locations. Successful manual suppression, therefore, limits the extent of the fire to the cabinet in which it initiates or to localized damage if it starts outside of a cabinet. Spreading of the fire beyond the initiating cabinet is assumed to force the evacuation of the Control Room.

Relay Room

The event tree for fire in the Relay Room is also similar to the transient event tree. The differences are:

1. The event SUP is included to account for the likelihood of the fire being suppressed before it can spread to locations impacting more than one injection system. Automatic suppression is assumed to limit the extent of the fire to the cabling of a single function, secondary cooling (main and auxiliary feedwater). These systems were selected to be failed during Relay Room fires that were suppressed because their loss has the highest impact on the core damage frequency of any of the systems credited in the analysis of this area. The feedwater system also initiates a plant trip if it fails. The probability assigned to the failure of Relay Room suppression is estimated to be 4E-2 (CO_2) as discussed in Section B.2.8.

2. The event HSDP is included to account for the operators' ability to recognize the need to successfully transfer control of the plant to the HSDPs and to shut down the plant from that location. This is the same event as described above for the Control Room fire and the probability of failure of this event is estimated to be 3.4E-3.

It is assumed in this analysis that when the fire is suppressed by automatic suppression equipment, it does not spread to other locations. Automatic suppression, therefore, limits the extent of the fire to the main feedwater and auxiliary feedwater cabling.

This event tree was quantified using the same methods used in the internal events PRA for the transient tree and the results of that quantification are provided in Table B.2.11.1.

B.2.10.3 Fire in AFW Pump Room

This event would also follow the transient event tree logic. However, credit was taken for fires being suppressed before they could spread beyond the location where the fire initiated within an area. The most severe heat load due to a fire in either of these areas would occur due to a postulated oil leak from a pump. Using the FIVE methodology, it was determined that the sprinkler system could be actuated prior to the thermal damage threshold being reached in overhead cable trays. The probability of failure of automatic suppression in these areas is 2.02E-2 per demand (from FIVE). This suppression factor was applied to determine the CDF for unsuppressed fires.

Fires that are suppressed in these areas were assumed to result in a transient (i.e., manual shutdown) with one component unavailable, the component in which the fire started. The most limiting case for each of the AFW pump rooms is to assume that the fire starts in the motor-driven AFW pump (the instrument air compressors are also located in these rooms). Assuming this pump is unavailable, but all other equipment is unaffected by the fire and is subject only to random failures, results in a negligible CDF for suppressed fires in the AFW pump rooms.

Credit for automatic fire suppression in the AFW pump rooms was applied through the use of recovery actions following sequence quantification. Therefore, no event tree was created to specifically model a fire in this area (followed the transient event tree logic for quantification). This was done since equipment was assumed to have actually failed for this fire, as opposed to controls for remote operation of the equipment from the control room. For fires in the Control and Relay rooms, a separate event tree was required because credit for equipment operation could still be taken if local control could be established by the operator at the Hot Shutdown Panel (HSDP). Note that the HSDPs are physically located in the AFW pump room.

B.2.10.4 Accident Sequence Classification

This section discusses the binning of core damage sequences into functional categories based upon characteristics of the accident sequences with respect to reactor and containment conditions at the time core damage is assumed to occur. These functional categories are called "accident classes".

The potential types and frequencies of accident scenarios at a nuclear power plant cover a broad spectrum. In order to limit these sequences to a manageable number, sequences with similar functional characteristics are grouped together. Three such functional classes were defined for the Prairie Island fire IPEEE:

Class TEH	Transient-initiated events in which both MFW and AFW systems become unavailable. Bleed and feed cooling of the RCS fails, causing core uncovery with the reactor at high pressure for these sequences. Core uncovery occurs relatively early (within a few hours of the failure of MFW and AFW).
Class TLH	Transient-initiated events in which both MFW and AFW systems become unavailable. Bleed and feed cooling is successful, but high head recirculation fails. Core damage occurs relatively late (i.e., approximately 8 to 10 hours) after the accident, and at high RCS pressure. Core damage is assumed to occur at a high reactor pressure.
Class SEH	These sequences are characterized by RCP seal LOCAs with failure of short-term reactor coolant inventory control. Core damage occurs early and at high RCS pressures.

These accident classes are typical of other PRAs and are a subset of those used in the Prairie Island internal events PRA. Other accident classes that were not considered to be applicable to the fire PRA include:

Class FEH, FLH	These classes are characterized by breaks in cooling water line which result in floods. These breaks cannot be initiated by fires, and the probability of a break concurrent with a fire is extremely low. Therefore, these accident classes are not applicable.
Class GEH, GLH	These classes are associated with steam generator tube ruptures. These are not considered for reasons similar to those discussed above for FEH and FLH.
Class SLL	This class is characterized by large or medium LOCAs. No credible fire-related large or medium LOCAs were identified.
Class V	This class is the interfacing system LOCA class. No fire-related mechanisms for Class V sequences were identified, and therefore this class is not considered.
ATWS Classes	No fire initiator was identified that could credibly lead to a failure of the reactor protection system. The simultaneous, independent failure of the reactor protection system or of control rod insertion during a fire is probabilistically insignificant.

Figure B.2.10.1 Fire-Induced Transient Event Tree

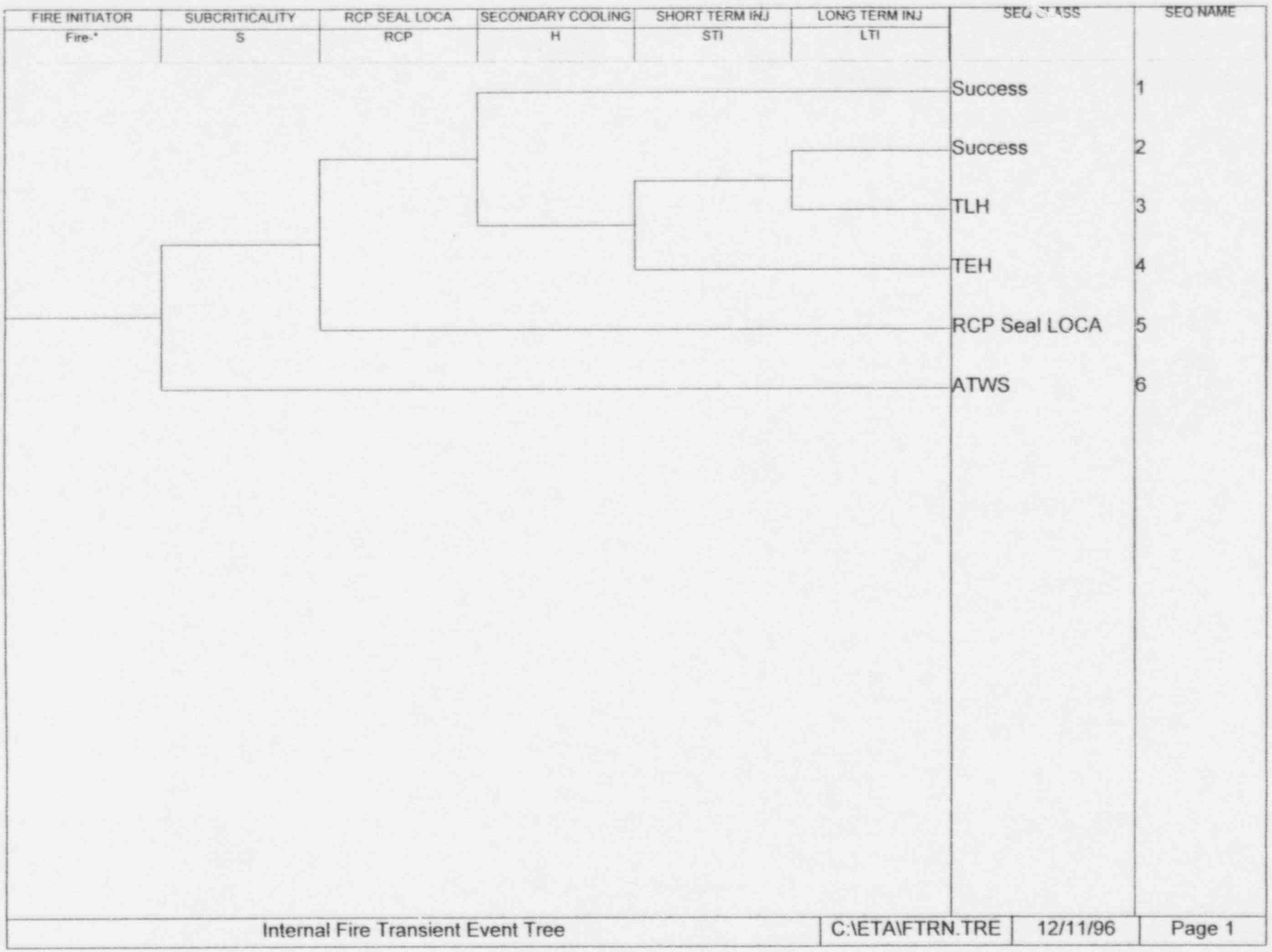


Figure B.2.10.2 Fire-Induced RCP Seal LOCA Event Tree

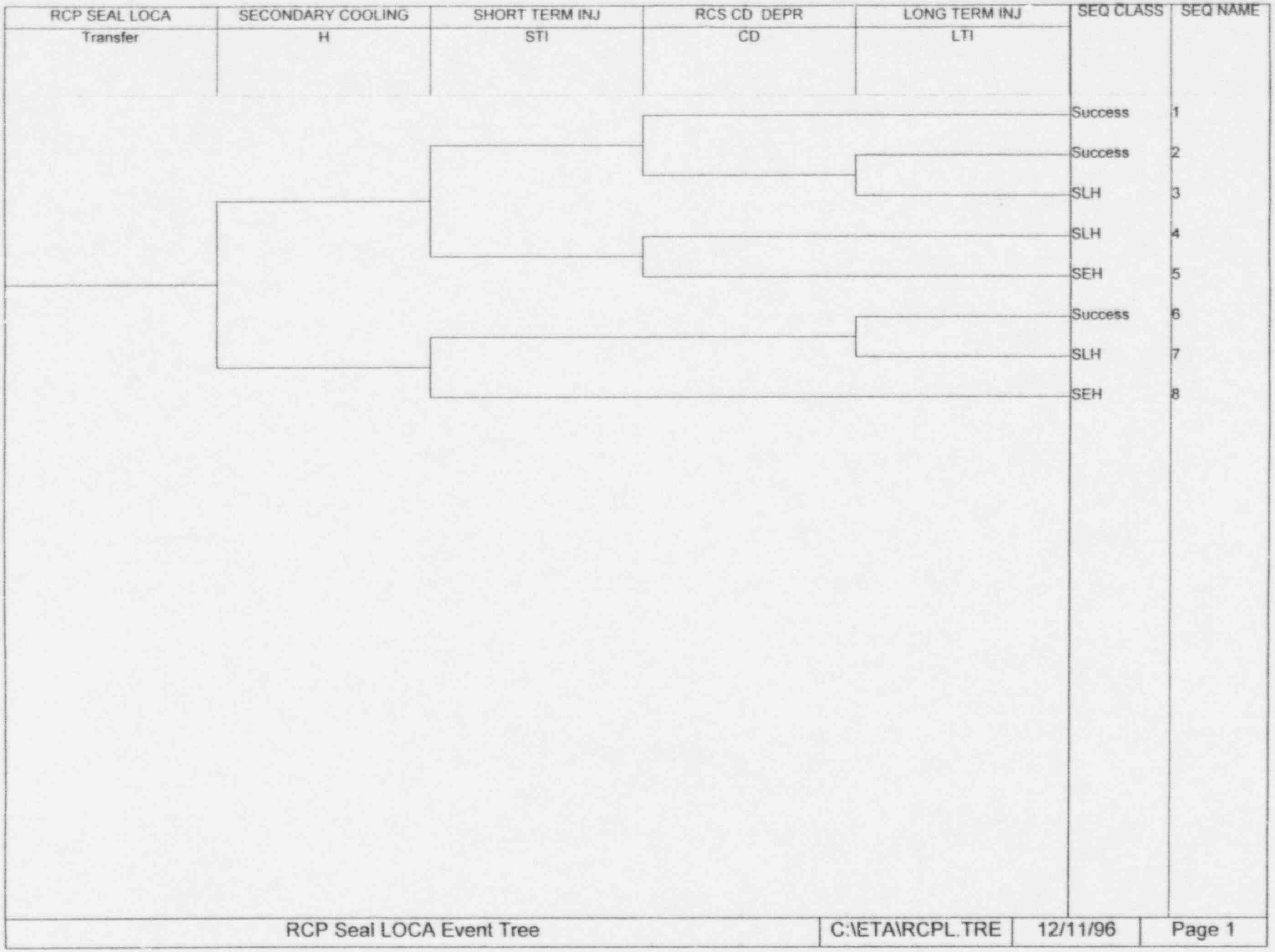
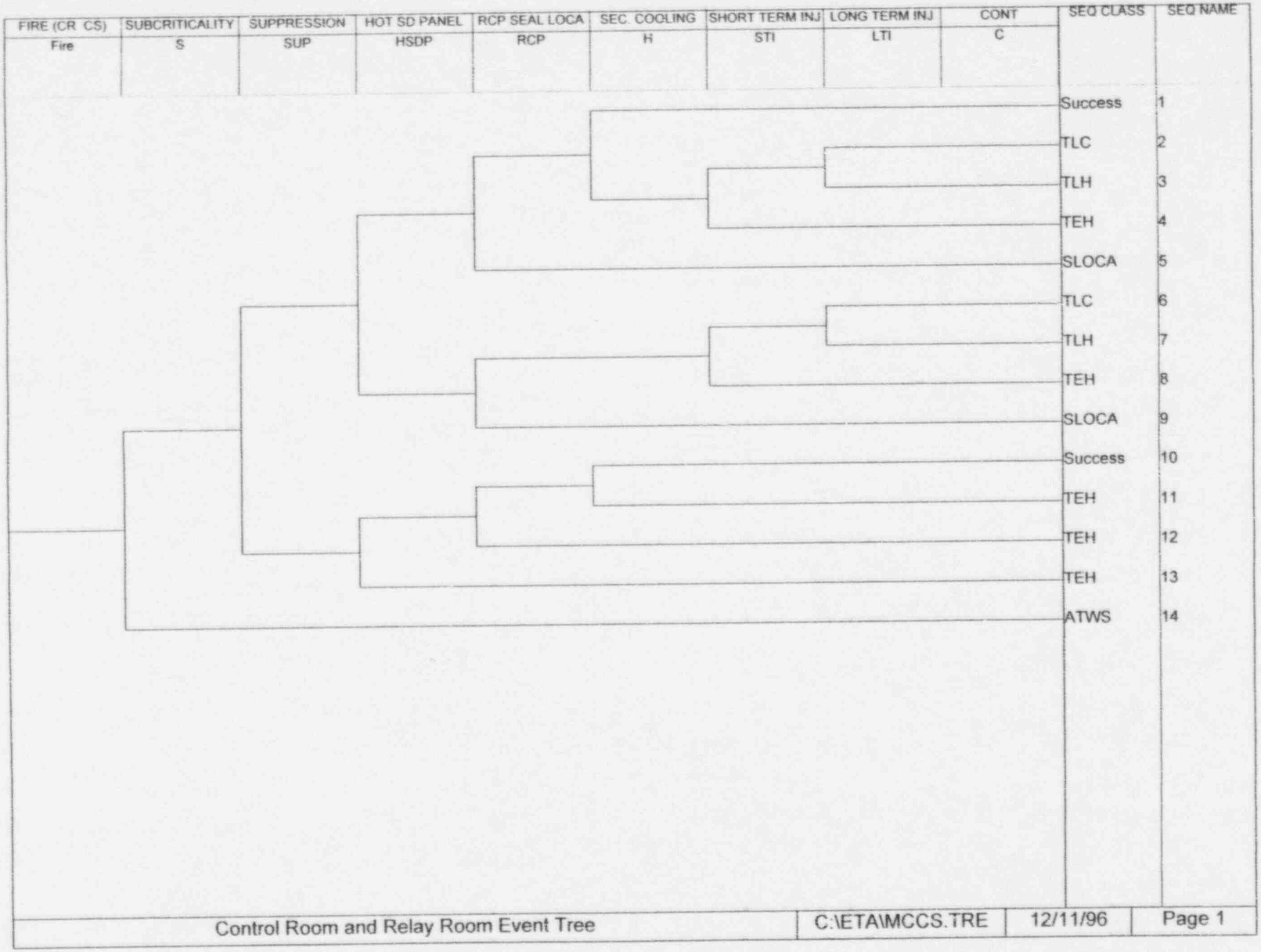


Figure B.2.10.3 Fire-Induced Transient Event Tree, Control Room & Relay Room Area



B.2.11 Analysis of Fire Sequences and Plant Response

This section gives the results of the fire sequence quantification, first by accident class and then by fire area. Important assumptions, fire initiators, operator actions and hardware failures that drive the accident class results are given in Section B.2.11.1. Important cables assumed to be damaged by a fire in a given area are discussed in Section B.2.11.2.

The following screening criteria were used to identify sequences to be discussed in this section of the report. This criteria is identical to the functional reporting requirements presented in Generic Letter 88-20 as required by NUREG-1407.

1. Functional sequences with a CDF greater than 1E-6 per year. (Functional sequences for the Prairie Island fire IPEEE are the accident classes defined in Section B.2.10. All the accident classes meet this criteria and are discussed in detail below. Also, core damage frequency results by fire area that meet this criteria are discussed in detail below. Result by fire area that are greater than 1E-7 per year are reported in Table B.2.11.1.)
2. Functional sequences that contribute five percent or more to total CDF. (All the accident classes meet this criteria and are discussed in detail below. Also, fire area results that contribute more than 2% of the total are discussed in detail below. Results by fire area that contribute more than 0.1% of the total are reported in Table B.2.11.1.)
3. Sequences determined by the utility to be important contributors to CDF or containment performance.

B.2.11.1 Important Accident Classes

Class TEH: The sequences within this class were characterized by an early core melt with the reactor at high pressure. This class contains sequences totaling 2.26E-5/year or approximately 36% of the overall internal fire events CDF. This class was dominated by sequences initiated by fires in the Control and Relay Rooms, Turbine Building Ground and Mezzanine Floor Unit 1 and the "A" Train Hot Shutdown Panel and Instrument Air Compressor/AFW Pump Room.

Important assumptions applicable to this class that are reiterated from the internal events PRA:

1. It has been shown through MAAP analysis that only one pressurizer PORV is required for successful bleed and feed cooling.
2. The motor-driven AFW pump from the second unit can be crosstied to Unit 1 steam generators. A limitation on this crosstie was included in the fault tree for AFW such that if a dual unit initiating event occurred and the Unit 2 turbine-driven auxiliary feedwater pump failed, the Unit 2 motor-driven feedwater pump could not be crosstied to Unit 1 as it would be required on Unit 2. It should be noted that all fires were conservatively assumed to result in shutdown of both units, thereby limiting credit for this crosstie.

3. It is assumed that the pressurizer PORVs cannot operate after instrument air has been lost. There are air accumulators on each PORV that are designed to allow approximately 15 cycles of valve operation after loss of instrument air. Bleed and feed requires sustained open times for the PORVs. It is not known how long the PORVs may remain open while on the air accumulators so it was conservatively assumed they are unavailable on loss of air.

4. Feedwater addition through the condensate pumps is not credited in the IPE as the majority of the failures for feedwater also fail condensate. Therefore, it was felt that this method of feedwater addition would not significantly reduce the potential for loss of secondary cooling.

The most significant fire initiating events were:

1. Fire in the Bus 121 480V switchgear room (FA 22) accounts for 36% of the core damage frequency in this accident class. Components affected by this fire include the Unit 1 motor-driven AFW pump and control circuitry for the Unit 2 turbine-driven pump. Both trains of SI are available to support bleed and feed cooling, if required.

2. Fire in the Turbine Building Ground & Mezzanine Floor Unit 1 (FA 69) accounts for 22% of the contribution to Class TEH CDF. A fire in this area is assumed to disable feedwater and the #11 AFW pump, three of the cooling water pumps (due to power and control cables passing through this area), as well as power to the 1K2 and 1KA2 MCCs. The #12 and #21 AFW pumps are available for S/G makeup.

3. The Relay Room (FA 18) accounts for 13% of the TEH accident class. These accident sequences are dominated by a failure to suppress the fire in the Relay Room, followed by an inability to establish turbine-driven AFW operation from the Hot Shutdown Panel.

4. The Aux Building Ground Floor Unit 1 (FA 58) accounts for 9% of the total TEH core damage frequency. AFW operation is largely unaffected by fires in this area, limiting the importance of the area to this accident class.

5. Fire in the "A" AFW pump area (FA 31) accounts for about 8% of the fire-initiated contribution to Class TEH CDF. These sequences are a result of failure to suppress the fire and unavailability of the "B" AFW train. An unsuppressed fire in this area is assumed to result in loss of instrument air (assuming operator failure to cross-tie station air to instrument air), MFW and #12/22 AFW pumps. The turbine-driven AFW pump remains to provide steam generator makeup.

The most significant operator actions contributing to this accident class were:

1. Failure to suppress the fire in the Control Room/Relay Room. Approximately 30% of the core damage associated with this accident class results from sequences in which fire suppression in the Control Room or Relay Room is unsuccessful. Failure to suppress the fire (operator inability to suppress a fire in the Control Room and automatic suppression failure in the Relay Room) followed by failure to take control of the plant at the Hot Shutdown Panel dominated this area.

2. Failure to cross-tie service air to the instrument air system contributes 23% of the core damage associated with this accident class. This operator action is assumed to apply to accident sequences in which instrument air is lost to support MFW or bleed and feed.

3. Failure of the operator to line up #21 AFW pump to Unit 1. Approximately 4% of the core damage frequency associated with this accident class resulted from failure of this action. This operator action is assumed to be required when loss of Unit 1 secondary cooling occurs, and it is only credited if the Unit 2 turbine-driven pump is available to accommodate Unit 2 decay heat removal. (In the accident sequence quantification, the conservative assumption is made that both units are shut down as a result of the fire.)

Important hardware failures associated with this accident class include:

1. Failure of the #11 and 12 AFW pumps to start and run. At least one of these two pumps plays a role in providing secondary cooling for each initiator.

2. Failure of the #12 and 22 diesel-driven cooling water pumps to start and run. The diesel-driven pumps play a significant role in providing support for component cooling water, main feedwater or instrument air operation in a number of the fire areas.

Class TLH: Sequences in this class were characterized by events with late core melt at high pressure. Class TLH sequences made up approximately 5% of the fire-initiated CDF at Prairie Island. They had a combined sequence frequency of 3.2E-6 per year.

The important assumptions made for Accident Class TEH also apply to the TLH Accident Class.

Significant fire initiating events for this accident class were:

1. Suppressed fires in the Control and Relay Rooms (FAs 13 and 18, fire limited to a single cabinet) account for 57% of the fire-initiated contribution to Class TLH CDF. That these fires dominate the TLH accident class is a result of the assumption that all fires in the Control Room affect the operation of AFW even if the fire is suppressed.

2. Fire in the Turbine Building Ground & Mezzanine Floor Unit 1 (burn sequence 69) accounts for 42% of the contribution to Class TLH CDF. A fire in this area is assumed to disable feedwater as well as power to the 1K2 and 1KA2 MCCs (which power the 11 and 13 charging pumps as well as component cooling valve MV-32094).

The most significant operator actions contributing to this accident class were:

1. Operator fails to initiate high head recirculation. This accounts for 58% of the Class TLH CDF. Again, a conservative assumption has been made that Control Room and Relay Room fires affect the ability to operate AFW except from the hot shutdown panel. Loss of AFW is assumed to lead to the need for bleed and feed and ultimately high head recirculation.

2. Failure to successfully control the plant from the hot shutdown panel for fires in the Control Room accounts for 55% of the Class TLH CDF contribution.

Important hardware failures associated with this accident class include:

1. Random hardware failure is not an important contributor to core damage sequences making up this accident class. Hardware failures are found in less than 20% of the core damage contribution. Failure of AFW components, specifically the #12 AFW pump, comprise the majority of the core damage contribution due to hardware failures.

Class SEH: Class SEH events were accident sequences resulting in early core melt at high pressure as a result of a seal LOCA (SEH). The core damage probability for this accident class was determined to be 3.73E-5 per year due to fires, or approximately 59% of the total.

Assumptions for Class SEH events were:

1. In the fire PRA, no credit was given for cooldown and depressurization of the RCS to initiate shutdown cooling following a seal LOCA. This results in the SI system being a mandatory injection source for a seal LOCA.

2. It is conservatively assumed that the SI pumps fail immediately on loss of component cooling as component cooling provides cooling for lube oil and seal cooling. In reality, the pump may continue to operate for a length of time and the operator could cycle pumps to prevent lube oil overheating.

Significant fire initiating events for this class were:

1. Fires in the Auxiliary Building Ground Floor Unit 1 (FA 58) account for 62% of the core damage associated with this accident class. These fires are significant in that only one train of component cooling is available for RCP seal cooling if all equipment in this area is assumed to fail. Crosstieing to Unit 2 component cooling is credited for sequences containing random failure of the surviving train of component cooling.

2. 4kV Safeguard Switchgear Room—Bus 15 (FA 81) contributes 10% of the CDF associated with this class. All three charging pumps and a train of component cooling are assumed to be affected by a fire in this area. Train B component cooling remains to provide seal cooling.

3. 480V Safeguards Switchgear Room—Bus 111 (FA 80) contributes 7% of the CDF associated with this class. This area supports a number of Train A components.

4. "B"Train Hot Shutdown Panel A Air Compressor/AFW room (FA 32) contributes 6% of the CDF associated with this accident class. All three charging pumps and a train of component cooling are assumed to be failed as a result of a fire in this area. Train B component cooling remains to provide seal cooling.

The most significant operator actions in Class SEH were:

1. Failure to manually crosstie the component cooling between units is found in cutsets accounting for 54% of the core damage attributable to this accident class. This operator action is most important for fires in the Aux Building Ground Floor (fire area 58) where all

three charging pumps and a train of component cooling are assumed to be damaged as a result of the fire. Failure of the remaining train of CC would necessitate this operator action. Although the action is covered by a procedure and is relatively simple, the operator will be performing the task under stress and will be relatively close to the fire. As a result, a relatively large screening value of 0.3 probability of failure for this action was used in the analysis. The local manual valves that are required to be opened for the cross-tie action are located at the edge of the fire area (between the CC heat exchangers, at the boundary of Fire Areas 58 and 73) with very little combustible material nearby. As a result no significant fire is expected to propagate to the area where the valves are. In addition, because the valves are at the edge of the fire area, the operator can go to their location from the Unit 2 side of the auxiliary building ground floor.

2. Failure of the operator to start the standby component cooling train contributes to 21% of the cutsets in this class. This operator action is required when the normally operating train of component cooling water is affected by the fire.

Important hardware failures associated with this accident class include:

1. Various hardware failures of the component cooling system are found in 37% of the cutsets in the Class SEH contribution. The primary hardware failures in this class consist of failure of the valves isolating cooling water from the component cooling water heat exchangers to open. These failures are found in cutsets accounting for 28% of the total CDF associated with Class SEH failures. Failures of the cooling water system supply account for most of the remaining CDF.

B.2.11.2 Important Fire Areas/Rooms

As shown in Figure B.1.4.3, 95% of the plant risk associated with internal fires can be traced to nine fire areas/burn areas. Attachment 1 contains floor plans showing the locations of the fire areas. These areas are:

1. Auxiliary Building Ground Floor Unit 1 (FA 58),

2. 480V Safeguards Switchgear Room—Bus 121 (FA 22),

3. Turbine Building Ground & Mezz Floor Unit 1 (FA 05, 08, 14, 21, 27, 57, 69, 94),

4. Relay (cable spreading) Room (FA 18),

5. 4KV Safeguards Switchgear Room—Bus 15 (FA 81),

6. 480V Safeguards Switchgear Room—Bus 111 (FA 80),

7. Train "B" Hot Shutdown Panel and Air Compressor/AFW Room (FA 32),

8. Control Room (FA13), and

9. Train "A" Hot Shutdown Panel and Air Compressor/AFW Room (FA 31).

This section provides the detailed plant response for each fire area/sub-area not previously screened from consideration. The quantification results presented in Table B.2.11.1 include:

1. The sub-area in which the fire occurs,
2. The frequency of fire ignition in that area,
3. The systems/subsystems potentially affected by a fire in that area,
4. The core damage frequency (CDF) for this fire, assuming all the systems in this specific area have failed,
5. Amplifying remarks where appropriate.

<u>Auxiliary building 695' (Area 58):</u> This sub area contains many components that are necessary for safe shutdown of the plant. Both trains of Safety Injection, RHR and Component Cooling as well as all three charging pumps are located in this area. In addition to the components physically located in this area, cables powering or controlling other equipment (MFW, AFW, IA, etc.) also transit the area.

Although this is an extremely large area and most of these components are sparsely located with significant distance between key equipment, a fire anywhere in this area is assumed to engulf the entire area. The only exceptions to this assumption are as follows:

1. The analysis credits the availability of power to MCC 1KA2 and from MCC 1KA2 to the motor-operated valve MV-32146 (on cooling water side of 12 CC heat exchanger). This assumption is based on a fire spread analysis which takes into account all combustibles in the vicinity of the MCC and the fact that the subsequent cables are fire protected. Similarly, cables located directly above the CC heat exchangers are not assumed to fail since there are no combustibles in the area. AFW pumps 11, 12 and 21 all remain available. In addition, Train B component cooling is credited to be available due to fire wrapping of critical power and control cables. No fire suppression is credited for this fire area. An operator action is credited for this area to cross-tie Unit 2 component cooling should random failure of Train B component cooling occur.

2. Fire area 58 is located next to fire area 73 (Unit 2 Auxiliary building 695'). A fire that initiates in 58 is assumed not to spread to fire area 73 due to a relatively large open area that separates the two fire areas. The only combustibles in this open space are cables in horizontal cable trays. Such combustibles are not conducive to fire spread across significant distances.

   This fire area produces 44% of the total core damage frequency for internal fires. The accident class that is dominant is SEH which represents 93% of the total core damage frequency for this fire area. Train B component cooling from Unit 1 and the cross-tie from Unit 2 are available to protect against loss of reactor coolant pump seals. All three charging pumps and Train A component cooling are physically located in this area and are assumed to be failed.

480V Safeguards Switchgear Room—Bus 121 (Area 22): Bus 121 provides power for Train B 480V equipment. Unit 1 components with power or control circuitry in this area include the motor-driven AFW pump, #12 component cooling water valve MV-32146, and the #11/13 charging pumps. Control circuitry for the Unit 2 turbine-driven AFW pump is also routed through this area. Fuel supply for the 22 diesel cooling water pump is dependent on panels ultimately powered from Bus 121 as well as the 21 safeguards screenhouse roof exhaust fan/dampers.

Area 22 accounts for 14.1% of the total core damage frequency. The bulk of the core damage sequence frequency (90%) is associated with class TEH. Only 9% of the potential for core damage results from sequences leading to seal LOCA.

The area was analyzed assuming all equipment and cables located in the room were damaged by the fire. No credit for manual fire suppression was taken.

The Unit 1 turbine-driven feedwater pump is the principal means of providing secondary heat removal for fires in this area. Should secondary cooling be lost, the #12 cooling water pump is available along with either the #11 or #121 cooling water pumps to assure bleed and feed capability through support of instrument air compressors and component cooling.

Turbine Building Ground & Mezzanine Floor Unit 1 (Fire areas 05, 08, 14, 21, 27, 57, 69, and 94): This area represents one of the higher fire initiating frequencies due to turbine oil and gas fires. A fire in this area has the potential to fail all of main feedwater. Both feedwater pumps and all three condensate pumps are physically located in this area. Other key components located in this area are cables supporting the operation of the #11 AFW pump, and the main power cables between 480VAC bus 121 and MCCs 1K2 and 1KA2. MCC 1K2 powers the #11 and #13 charging pumps as well as component cooling water valve MV-32094. MCC 1KA2 powers cooling water valve MV-32146 as well as "B" train safety injection valves. Valve MV-32146 is on the cooling water side of the #12 CC heat exchanger.

This area accounts for 10.2% of the total core damage frequency. The TEH and TLH classes are the primary contributors to core damage (76% and 21%, respectively) for this area. The availability of both the motor and turbine-driven AFW pumps limits the risk significance of fire in this area.

Control Room/Relay Room (Fire areas 13 & 18): The Control and Relay Rooms contain controls, monitoring instrumentation, and cables for most of the equipment used to achieve safe shutdown of the plant. Failure to suppress a fire in these areas was assumed to disable all equipment that could not be controlled locally or from the HSDPs.

Most Control and Relay Room fires start in electrical cabinets or panels. Fire damage or subsequent suppression induced damage were assumed to render all circuits within the initiating cabinet inoperable. Fires within enclosed cabinets (Relay Room) were assumed not to spread beyond the initiating cabinet. Fires in Control Room cabinets were assumed to spread to engulf the area if not successfully suppressed, forcing the evacuation of the Control Room. Fires

starting outside of cabinets were also assumed to spread and engulf either the Control Room or Relay Room if not successfully suppressed.

If the fire was suppressed, all equipment not controlled from that panel was assumed to be available for use and would fail only due to random causes. If the fire was not suppressed, evacuation of the Control and Relay Rooms is assumed necessary and only equipment controlled from the HSDPs was considered available.

General area fires (i.e., fires initiating outside of enclosed electrical cabinets) within the Control and Relay Rooms were assumed to engulf the entire room if not suppressed. Manual suppression was credited in the Control Room and automatic suppression was credited in the Relay Room. If suppression was successful, the cabling associated with at least one system (AFW) was assumed to be damaged. Suppression therefore limits the extent of the fire to a single system.

These fire areas combined produce 9.4% of the total internal fire CDF. Class TEH and Class TLH sequences comprise the majority of the risk (69% and 31%, respectively) associated with Control Room and Relay Room fires. Class TEH sequences were dominated by operator inability to take control at the HSDPs in time to provide adequate core cooling following failure to suppress the fire in the Control Room or the Relay Room. This procedure is detailed in NSP Plant Safety Procedure F5, Appendix B, "Control Room Evacuation (Fire)." Core damage from Class TLH sequences consists of failure to initiate high head recirculation or take control of the plant at the HSDPs following successful suppression of the fire. Efforts to repair and recover these components were not credited in these accident sequences.

<u>4kV Safeguards Switchgear Room—Bus 15 (Area 81)</u> This fire area contains equipment that provides power for Train A components such as the #11 SI and RHR pumps, the #11 component cooling pump as well as power to 480V Switchgear Bus 111, which supports the operation of the #12 charging pump. Control cables for feedwater and condensate also transit this area.

This area was analyzed assuming all switchgear and cables located in the room were damaged due to the fire. No fire suppression was credited.

This fire area contributes only 5.8% to the total core damage frequency. Nearly all of this risk is due to RCP seal LOCA (accident class SEH). Very little is associated with accident class TEH due to the availability of both AFW pumps as well as the ability to crosstie the motor-driven pump from Unit 2. Train B component cooling as well as the #11 and #13 charging pumps limit the potential for a seal LOCA. Should bleed and feed be required for a seal LOCA due to random failures, Train B SI is available to provide adequate core cooling.

<u>480V Safeguards Switchgear Room—Bus 111 (Area 80)</u> Bus 111 provides power for Train A 480V equipment. Equipment affected by fires in this area include Train A SI and RHR, cooling water valve MV-32145 and charging pump #12. Control circuitry for the 21 motor-driven AFW pump is routed through this area. Fuel supply for the #12 diesel cooling water pump ultimately is dependent on power provided from Bus 111.

Area 80 accounts for only 4.7% of the total core damage frequency, much less than that associated with the Bus 121 480V switchgear room. Approximately 85% of this is due to accident SEH. The availability of both Unit 1 motor-driven and turbine-driven AFW pumps for this area largely accounts for the difference between the core damage frequencies for Bus 111 and Bus 121 480V switchgear fires.

This area was analyzed assuming all equipment and cables located in the room were damaged by the fire. No credit for manual fire suppression was taken.

The 12 AFW pump is available to provide secondary heat removal for fires in this area. Seal LOCAs are precluded by a train of component cooling or either of the #11 or #13 charging pumps.

"A" Train Hot S/D Panel & Air Compressor / AFW pump area (Fire Area 31): This area contains the #12 AFW pump, #22 AFW pump, MCCs 2A1 and 2A2, 123 instrument air compressor and the "A" hot shutdown panel. In addition to the equipment physically located in the area, cables for power to MCC 1AC2 and various other Train B components are routed through this area. Although only 123 instrument air compressor is physically located in this area, 121 and 122 instrument air compressors are assumed to fail in this area due to cables traversing through the area. An automatic wet pipe suppression system is available and was credited in this area. If the suppression system actuates, it will prevent any fire spread or collateral damage and limits the damage to the initiating component. Otherwise the fire is assumed to engulf the entire area.

In the event of a fire in this area, only #11 AFW pump is available for secondary side cooling (21 AFW pump is assumed to be unavailable to Unit 1, since 22 AFW pump has failed, requiring 21 pump to supply Unit 2). With the loss of instrument air, failure of the operator to cross-tie station air to instrument air leads to the inability to bleed and feed and therefore loss of short term injection. This results in the TEH accident class dominating this fire area (>99%). Because of the installed automatic fire suppression capability, this area represents only 2.9% of the total internal fire CDF.

"B" Train Hot S/D Panel & Air Compressor / AFW pump area (Fire Area 32): This area contains the #11 AFW pump, #21 AFW pump, MCCs 1A1 and 1A2, instrument air compressors 121 and 122, and the "B" hot shutdown panel. In addition to the equipment physically located in the area, cables for the #11 MFW discharge valve, MCC 1K1 and various other Train A components are routed through this area. Unlike fire area 31, the ability to cross-tie station air to instrument air is not available in this area since the valve that enables this operator action is physically located in this AFW pump room. An automatic wet pipe suppression is available and was credited in this area. If the suppression system actuates, it will prevent fire spread or collateral damage and limits the damage to the initiating component. Otherwise the fire is assumed to engulf the entire area.

Unlike fire area 31, the TEH accident class does not contribute significantly to core damage for this fire area. A fire in this area most often would result in an SEH class accident due to loss of RWST as a source to charging and failure of 11 and 12 cooling water pumps. The motor operated valve MV-32060 fails to open automatically due to loss of 480 V AC power cables to MCC 1K1 which pass through this area. This results in reduced reliability for seal LOCA protection and higher contribution to the CDF by SEH class. Class SEH represents 95% of the CDF contributed by fire area. Overall, this fire area represents 3.6% of the total internal fire CDF.

Table B.2.11.1 Prairie Island Plant Response to Area-Specific Fires

Area Number	Area Description	Train/Function Failed by Fire	Train/Function Available	Ignition Freq.	Transient (TEH)	Transient (TLH)	SLOCA (SEH)	Total CDF	Comments
13	Control Room	All equipment not controlled from the HSDP failed for fires requiring Control Room evacuation	#11 AFW Pmp #12 CHG Pmp	2.07E-2	1.05E-6	9.17E-7	< 1E-8	1.97E-6	Credit for manual suppression of the fire. Control of AFW from the HSDP is modeled for all CR fires.
18	Relay and Cable Spreading Rm., Units 1 & 2	All equipment not controlled from the HSDP failed for fires that are not suppressed	#11 AFW Pmp #12 CHG Pmp	2.07E-2	3.03E-6	9.17E-7	< 1E-8	3.94E-6	Credit for auto suppression of the fire. Control of AFW from the HSDP is modeled.
20	Unit 1 4KV Safeguards Swgr. (Bus 16)	MFW/COND, #12 SI Pmp, #12 CS Pmp, #2DG, #12 CC Pmp, #12 AFW, #11/13 CHG Pmps, #11/22/121 CL Pmp, #12 RHR Pmp, #122 IAC	#11, 21 AFW #11 CC #12 CHG #11 SI #21/12 CL	2.04E-3	5.70E-7	< 1E-8	4.10E-7	9.78E-7	
22	480V Safeguards Swgr. (Bus 121)	#122 IAC, #11/13 CHG Pmps, #12/22 AFW Pmps, #21/22 CL Pmp	#11 AFW Pmp #12 CHG Pmp #11/12 CC Pmp #11/12 CL #11,12 SI	2.09E-3	8.05E-6	3.55E-8	8.02E-7	8.90E-6	
31	"A" Train Hot S/D Panel & Air Comp/AFW Room	#12/22 AFW Pmps, IA, MFW, #22 CL Pmp, CHG-All Pmp, Service Air	#11 AFW Pmp #11/13 CHG Pmp #11/12 CC #11/12/121/21 CC	1.52E-3	1.82E-6	< 1E-8	< 1E-8	1.82E-6	Auto suppression assumed to prevent fire spread to entire area. Manual action to crosstie service air is assumed to allow continued operation of MFW.
32	"B" Train Hot S/D Panel & Air Comp/AFW Room	IA, #11 CC Pmp, #11/21 AFW Pmps, SI-All, #11 RHR Pmp, #11/12 CL Pmps, CHG Makeup, Bus 15, #12 SI	MFW #12 AFW #12 CC #21/22/121 CL Service Air	1.61E-3	1.11E-7	< 1E-8	2.14E-6	2.25E-6	Auto-suppression assumed to prevent fire spread to entire area.
34	Battery Room 12	#12 Battery, #12 CC Pmp, #12 AFW Pmp, #12 RHR Pmp, #12 SI Pmp, #123 IAC,	#11 Battery #11 CC Pmp #12 AFW Pmp #12 SI Pmp	1.18E-3	1.26E-7	< 1E-8	< 1E-8	1.33E-7	
36	Battery Room 22	Bus 23, DG #6, CL Pmp #21, Battery 22		1.13E-3	5.72E-8	< 1E-8	2.83E-7	3.46E-7	
37	Unit 1 480V Normal Swgr. (Bus 150, 160)	CL Pmps #11/12, A-MFW, Bus 13, Bus 150/160		2.10E-3	3.28E-8	< 1E-8	5.04E-7	5.38E-7	

Table B.2.11.1 (continued) Prairie Island Plant Response to Area-Specific Fires

Area Number	Area Description	Train/Function Failed by Fire	Train/Function Available	Ignition Freq.	Transient (TEH)	Transient (TLH)	SLOCA (SEH)	Total CDF	Comments
38	Unit 2 480V Normal Swgr. (Bus 250, 260)	CL Pmps #21/22, Bus 250/260, Bus 23		2.10E-3	< 1E-8	< 1E-8	1.14E-7	1.16E-7	
58	Aux Building Ground Floor Unit 1	B-MFW, #123 IAC, SI-All, CHG-All, CC Pump #11, RHR-All	CC Pmp #12 CC Xtie from U2 11, 12, 21 AFW	1.03E-2	2.08E-6	< 1E-8	**2.57E-5**	**2.78E-5**	Includes operator action to x-tie CC from Unit 2. Separation assumed to preclude fire spread to MCC1K1. Fire spread across FA 58/73 boundary assumed not credible.
B59	Aux Building Mezzanine Floor Unit 1 (FA 59, 84)	#11 AFW (Steam Supply), #12 CC Pmp, #11/13 CHG Pumps, #12-SI, #12-RHR	MFW #12/21 AFW #11 CC #12 CHG #11 SI	9.41E-3	1.05E-7	< 1E-8	6.94E-7	7.95E-7	Control cables for MV-32060 assumed to be unaffected by the fire.
B69	Turbine Building Ground & Mezz Floor Unit 1 (FA 05, 08, 14, 21, 27, 57, 94)	MFW/COND, #11 AFW Pump, #11/12/22 CL Pmp, #11/13 CHG Pmps, #12-SI, #12-RHR	#12/21 AFW #12 CHG #121/21 CL #11 SI	1.94E-2	4.88E-6	1.35E-6	1.88E-7	6.44E-6	
B70	Turbine Building Ground & Mezz Floor Unit 2 (FA 07, 08, 23, 90)	#22 AFW Pmp, Bus 26	#11/12/21 AFW #11/12 CC #11/12/13 CHG #11/12 SI	1.66E-2	3.14E-8	< 1E-8	1.51E-7	1.82E-7	
73	Aux Building Ground Floor Unit 2	# 21 AFW Pmp, #12 CC Pmp, #123 IAC		2.53E-2	1.58E-7	< 1E-8	1.01E-7	2.59E-7	
80	480V Safeguards Swgr Room (Bus 111)	MFW, Bus 111, IA, #21 AFW, #12 CHG, #12 CL	#11/12 AFW #11/13 CHG #11/12 CC #11/12 SI	2.09E-3	4.32E-7	< 1E-8	2.51E-6	2.93E-6	
81	4KV Safeguards Swgr Room (Bus 15)	Bus 15, #11 RHR Pmp, #11 CC Pmp, #121 IAC, #11 SI Pmp, MFW/COND, #12 CL, CHG-All	#11/12/21 AFW #12 CC #11/22/121/21 CL #12 SI	2.03E-3	< 1E-8	< 1E-8	3.66E-6	3.67E-6	
CDF TOTAL					2.26E-5	3.23E-6	3.73E-5	6.32E-5	

B.2.11.3 Unit 2 Considerations

The preceding analysis focused on generating insights regarding the effects of a fire on Unit 1 of the Prairie Island Generating Plant. For reasons that are outlined in this section, similar quantitative results and insights would be expected for Unit 2.

Shared and Crosstied Systems

A number of systems at Prairie Island are common to both units in that they are either shared or can be crosstied to support important safety functions in either unit. The logic modeling for the Prairie Island Unit 1 fire PRA includes credit for specific Unit 2 systems as a result.

For example, the following systems are common to both Units 1 and 2. Fires affecting the operation of these systems would be expected to have similar effects on both units.

- Cooling Water
- Instrument Air
- Safeguards Chilled Water

Systems which can be crosstied between units in the event of random failures or failures resulting from a fire that were credited in the fire PRA include:

- Auxiliary Feedwater
- AC Power
- Component Cooling

Because of these shared and crosstied systems, many of the rooms containing Unit 2 equipment have been evaluated as a part of the Unit 1 fire analysis.

Symmetrical Systems

A number of the systems that cannot be crosstied are safety systems that are generally symmetrical between units both in terms of function as well as location. Examples of these types of systems important to the outcome of the fire PRA include:

- Charging
- Safety Injection
- Component Cooling (also a crosstied system)
- DC Power

Where these systems are symetrical between units, the effects of a fire in Unit 2 would be expected to be similar to Unit 1.

Application of Unit 1 Results to Unit 2

To estimate the effect that fires may have on Unit 2, a two step review was performed. The first step examined the dominant area from the Unit 1 fire PRA to determine if that area would also be expected to dominate the results for Unit 2. The second step was to identify any potentially significant asymmetries between the two plants that may have a significant impact on the quantitative results.

- Dominant Fire Area Review

The most significant fire area in the Unit 1 fire PRA is the Auxiliary Building Ground Floor (Area 58). This area constitutes over 40% of the total estimated core damage frequency due to fires for Prairie Island.

The corresponding area in Unit 2 is Area 73. As noted in Table B.2.1.1, the fire loading is very similar for both areas. Equipment located in area 73 includes both SI pumps, all three charging pumps, both trains of RHR as well as component cooling, similar to Unit 1. Both trains of Auxiliary Feedwater are available to provided secondary cooling. As a result, a reactor coolant pump seal LOCA would be the dominant contributor to core damage for Unit 2 as identified in the Unit 1 analysis. Power and control cables for a train of component cooling are protected to provide adequate seal cooling. An important operator action to reduce the potential for seal LOCA would be to crosstie a train of Component Cooling from Unit 1.

Given the similarity between Unit 1 and Unit 2 Auxiliary Building Ground Floors, the risk associated with a fire in Area 73 is expected to be dominant for Unit 2 as it was for Area 58 in Unit 1.

- Potentially Significant Asymmetries

As a result of recent modifications resulting in the installation of two new diesel generators, the most significant asymmetries which exist between Unit 1 and 2 are associated with the operation and layout of the AC distribution system. The following summarizes the differences between the two units in this regard.

The new Unit 2 emergency diesel generators are air cooled whereas the original diesels now tied to Unit 1 require cooling supplied from the Cooling Water System. This asymmetry would have little effect on the outcome of a fire PRA as no fire area is expected to result in a loss of offsite power sources.

The emergency buses for Unit 2 (Buses 25 and 26) are located in fire areas that are not separated by fire barriers from the diesel generators themselves. The diesel generators and emergency buses for Unit 1 (Buses 15 and 16) are in separate fire areas. The effect of this location difference is to increase the frequency of fires that may affect the emergency buses in Unit 2. Table B.2.6.3 shows the frequency of fires in areas that could affect Unit 2 4kv switchgear (for example, Train A areas include 101, 103, 105, 107, 109,

111, 115, 117, 123 and 127). At 1.7E-2/yr, the combined fire frequency for these areas is roughly an order of magnitude greater than that for Unit 1 4kv switchgear (Train A Area 81, 2.0E-3/yr).

The 121 cooling water pump is powered from 4kV Bus 27, which can be supplied from 4kVBus 25 or Bus 26 through local manual operator action. It is normally powered from 4kV Bus 25. As a result, a fire in Unit 2 affecting Train A AC power (and to a lesser extent, a fire in Unit 2 affecting Train B AC power) can also affect the operation of this cooling water pump.

The fuel supply for diesel pumps 12 and 22 are modeled as being dependent on Unit 1 AC power only. In addition, screenhouse ventilation for the diesel pumps as well as motor driven pump 121 is dependent on Unit 1 safeguards AC (in fact, a manual transfer exists for these functions to Unit 2 that was not credited in the Unit 1 analysis). Given this conservative modeling, the diesel cooling water pumps are not affected by fires associated with either of the two trains of AC power in Unit 2.

As noted above, the first asymmetry has little effect on the risk associated with fires as the potential for a loss of offsite power at the time of a fire is small.

The second and third asymmetries would have the impact of raising the risk of a fire in a Unit 2 train of AC power over that quantified for Unit 1 if only for the larger frequency of fires in areas containing important Unit 2 switchgear. However, the last item, the independence of the operation of the two diesel cooling water pumps from Unit 2 AC power, offsets any increase in Unit 2 switchgear fires.

Recall from the discussion of Unit 1 fire area 81 (4kv switchgear - Bus 15) that the fuel pump for diesel cooling water pump 12 is ultimately dependent on Train A AC power. Screenhouse ventillation for the two diesel cooling water pumps and pump 121 are also dependent on AC power. Therefore, loss of a train of Unit 1 AC as a result of a fire combined with the random failure of two cooling water pumps leaves only one cooling water pump available. As the success criteria for the Cooling Water System requires two pumps, it is assumed that the Cooling Water function is lost given these failures. Without Cooling Water, Component Cooling and instrument air eventually are assumed to fail. As instrument air supports normal makeup to the volume control tank, charging is assumed to be lost as well, leading to a reactor coolant pump seal LOCA.

This dependency of three cooling water pumps on Unit 1 emergency power does not exist in Unit 2. Additional random failures of cooling water pumps and charging would be required before a seal LOCA would be possible. Even with the larger potential for fires in the emergency trains of AC power, the frequency of core damage due to postulated fires in Unit 2 are expected to be similar to or possibly less than that for Unit 1.

B.2.12 Analysis of Containment Performance

As indicated in NUREG-1407, the focus of the fire IPEEE containment evaluation is to identify any severe accident issues unique to fire events that may involve early failure of important containment functions. The scope of this containment analysis is based on a review of the Level 2 analysis in the internal events PRA. The focus of the evaluation was to identify any potential early containment failure modes unique to fire events that had not already been evaluated as a part of the internal events PRA.

The NUREG-1407 guidance requires an evaluation of any fire-induced containment failures and other containment performance insights. Particularly, it should consider vulnerabilities found in the systems and functions which could lead to early containment failure or which may result in high consequences. These include containment isolation, bypass, and integrity, and systems required to prevent early failure. The conclusion of this review was that the types of challenges to containment are similar to that evaluated in the internal events PRA. No new or unusual means of challenging the containment were identified as a part of the IPEEE.

B.2.12.1 Containment Structures and Systems

A fire assessment was performed to identify any vulnerability that could lead to early failure of containment functions. The structures, systems, and components needed to ensure containment integrity, containment isolation, and prevention of bypass were reviewed.

The containments at Prairie Island are large dry concrete structures. The combustibles located in the containment consist of cable insulation, RCP lube oil and charcoal filter media. Because the containment contains few ignition sources and much of the combustible material is enclosed, a significant fire within each containment is not expected to occur. The spaces surrounding the containment also contain very little combustible material or have suppression systems that will limit the size of a fire. The screening criteria used in the FIVE methodology indicates that a significant fire in these areas is therefore not likely. The same methodology also indicates that fire spread between these areas is not credible. Therefore, because any fire in the spaces adjoining the containment will be contained within a single area and will be of limited duration and intensity, structural damage to the containment is not expected.

To help focus the analysis on containment penetrations that may contribute to a release, the following screening criteria were used to eliminate some penetrations from further consideration:

- Penetrations of open containment or reactor systems: if the system is not open to the containment atmosphere or the reactor, the probability of simultaneous failure of the isolation valve(s) in the system and a pipe break is considered negligibly small.
- Pipes with diameters less than or equal to 2 inches: aerosol plugging is considered likely to minimize the amount of leakage that could occur from these penetrations.

- Hatches and airlocks: these items are closed during operations as part of technical specification requirements and are opened only for monthly inspections of containment.
- Normally closed lines: lines containing normally locked closed valves, or lines containing closed valves that would not be expected to open during the course of an accident do not contribute significantly to containment isolation failure.

Nine penetrations did not meet the screening criteria identified above. A description of the piping configurations and the failures required to bypass containment for each of these remaining penetrations are discussed below:

- CVCS lines (Penetrations 11 and 12)

  The CVCS letdown penetration includes a normally open AOV in parallel with two normally closed AOVs, which together provide a range of flow control options. A single, normally open AOV located downstream can isolate all three parallel valves. Another line containing a normally closed MOV (MV-32234) joins the letdown line downstream of the three parallel valves. For isolation failure either the MOV must spuriously open, or both of the open AOVs must fail to close and remain closed.

  The CVCS charging penetration includes two check valves, a normally open AOV, and a normally open manual valve in series. The AOV does not receive an isolation signal. For isolation failure, both check valves must fail to close and remain closed.

- RCP Seal cooling lines (Penetrations 13A and B)

  These two lines each contain a check valve and a normally open manual valve. For isolation failure, the check valve must fail to close and remain closed.

- Instrument Air line (Penetration 20)

  This line includes two normally open AOVs in series. For isolation failure, both AOVs must fail to close and remain closed. However, two considerations effectively result in a relatively insignificant contribution for this penetration. First, the air system is effectively a closed system within containment, only subject to back-leakage through the valve operators. Second, no failure should be considered while this line is pressurized with instrument air.

- Containment Sump A Discharge (Penetration 26)

  This line includes two normally open AOVs in series. For failure, both valves must fail to close and remain closed for the mission duration.

- Containment Vacuum Breakers (Penetrations 41A and B)

  Each containment vacuum breaker line contains a normally open air-operated valve and an air-assist check valve (i.e., Instrument Air holds the check valve open). Failure results if both the AOV and the check valve in either line fail to close and remain closed.

* Makeup to Pressurizer Relief Tank (Penetration 45)

  This line contains a normally open air-operated valve in series with a check valve. Failure for this penetration involves failure of the AOV to close and remain closed, coupled with failure of the check valve to remain closed.

Fires can affect containment isolation valves in several ways: (1) failure of power cables or failure of motive power to solenoid-operated valves or air to air-operated valves will cause the valve to fail closed; (2) hot shorts in control cables to air-operated or solenoid-operated valves could possibly cause inadvertent valve opening; (3) failure of power cables to a motor-operated valve will fail the valve in its current position; and (4) hot shorts of control or power cables to a motor-operated valve could potentially result in a change of the valve's position. However, as discussed below, these failure modes are not expected to result in containment failure or bypass:

1. With one exception, the active valves associated with the unscreened penetrations are air-operated valves. These valves fail closed on a loss of air or power. Although extremely unlikely, if a hot short in one of these valve circuits were to occur that did not fail the protective fuse, manual recovery by removing fuses in the affected circuit would cause the valve to fail closed.

2. Similar to the control circuits on air-operated valves, it is extremely unlikely that a hot short in motor-operated valve control circuits could occur without first failing the circuitry required to reposition the valve or actuating the circuit's protective features, such as fuses. Additionally, control valve CV-31325 is in series with the MOV (MV-32234) in question. Much of the control cable associated with CV-31325 is in the vicinity of the cables associated with MV-32234. It is likely that a fire that would impact MV-32234 cabling would also damage cabling associated with CV-31325 causing it to fail closed. Finally, the fire areas where the majority of this cable is located (fire areas 59, 60) have a relatively low area core damage frequency.

For the reasons discussed above, fire-induced degradation of containment performance is expected to be negligible. There were no unique containment failure modes identified during the fire IPEEE analysis that differ from those identified in the internal events PRA.

B.2.12.2 Containment Systems

Systems important to maintaining containment integrity after a core damage event also were identified in the Prairie Island internal events PRA. A summary of these systems and the functions that they provide follows:

Containment Isolation
- Isolation Valves

Debris Cooling (in-vessel and Ex-vessel)
- High Head SI
- Low Head SI

Containment Spray

Containment Pressure Control
RHR (aligned for high head or containment spray recirculation)
Fan Coil Units

Radioactive Release Control
Containment Spray
Fan Coil Units

The components in many of these systems were included as a part of the Level 1 analysis performed for the Fire PRA.

In evaluating containment performance following a fire, any system or component which must be disabled in order to reach core damage was not credited as a means of avoiding containment failure. Table B.2.12-1 summarizes the systems which would be available to provide functions such as debris cooling and containment heat removal.

The accident sequence types defined in the internal events PRA are presented below. Each discussion supports the conclusions that (1) the majority of systems important to containment performance under severe accident conditions were considered as a part of the Level 1 analysis, and (2) the containment response to core damage following a seismic event is similar to that analyzed in the internal events PRA.

Containment Response

Three accident classes or accident sequence types dominate the results of the Fire PRA and are a subset of those included in the internal events PRA. These include:

TEH — Transients (non-LOCA) in which core damage occurs at high reactor pressure without high head injection

TLH — Transients (non-LOCA) in which core damage occurs at high reactor pressure without high head recirculation

SEH — LOCAs in which core damage occurs at high reactor pressure without high head injection

Transient Initiator at High Reactor Pressure Without Injection (Accident Class TEH)

For this accident class, core damage is assumed to occur as a result of the loss of secondary heat removal and high pressure injection in the bleed and feed mode. The primary system is intact for these types of accident sequences as the fire has not led to to sufficient failures that a loss of RCP seal cooling would occur. Should high head safety injection not be restored before core debris melts through the lower vessel head, then the reactor would depressurize when the lower head is breached. The response of containment at this stage of the accident is dependent on the fire-induced and random failures that have occurred.

For all but one fire area, initiation of injection systems would occur in the form of SI, RHR, or containment spray, or a combination of the three. The depressurization of the reactor on lower head penetration, the rise in containment pressure or manual initiation would result in RWST water being provided to the debris in the containment. These are the same systems available to provide debris cooling that were considered in the internal events PRA. Short-term challenges to containment include Direct Containment Heating (DCH), hydrogen combustion and steam explosions. The potential for containment failure due to these challenges was evaluated in the internal events PRA and was found to be low. The potential for and magnitude of these early challenges is not affected by any of the fire initiators.

The one fire area that would not necessarily result in RWST water being transferred to containment is the Auxiliary Building Ground Floor (Fire Area 58) as both trains of SI, RHR and containment spray are located in this area. The impact of the loss of these systems is on the potential for slowly evolving containment challenges, such as overpressurization or basemat penetration, as described below. The loss of these systems does not lead to any new early containment failure modes as a result.

For long-term debris cooling and containment pressure control, with one exception, sufficient systems are available to accomplish these functions. The one fire area that is again the exception is the Auxiliary Building Ground Floor containing all SI, RHR and Containment Spray pumps. Although Fan Coolers are available for long-term heat removal for this area, the lack of RWST inventory in the containment is assumed to leave debris uncovered, resulting in long-term pressurization of containment due to noncondensible gas generation from concrete interaction. This, however, is a slowly evolving containment challenge no different than identified in the internal events PRA that would take on the order of a day or more to challenge containment to its ultimate capacity.

Transient Initiator at High Reactor Pressure Without Recirculation (Accident Class TLH)

This accident class is similar to the previous one in that secondary heat removal is lost. Bleed and feed operation is successful in providing short-term core cooling. Core damage is assumed to result from failure to successfully align recirculation.

Because of bleed and feed operation, the contents of the RWST have been successfully transferred to containment at the time of core damage. The volume of water in the primary system combined with the RWST inventory results in the submergence of the lower vessel head. As long as condensation of steam continues and the water is returned to the reactor cavity, it is likely that core melt progression can be terminated within the vessel. The early challenges to containment for this accident class are a subset of those that are postulated for Class TEH due to the potential for preventing transport of the core debris into containment. These early challenges are similar to those defined in the internal events PRA for this accident class.

For each of the dominant fire areas in this accident class, several modes of containment heat removal are available. These include fan coolers as well as containment spray recirculation.

RHR recirculation is also available should lower head penetration occur, resulting in the depressurization of the reactor. Due to the availability of long-term decay heat removal sytems, there is little potential for long-term overpressure challenge of containment.

Seal LOCAs Without Safety Injection (Accident Class SEH)

The fire initiators that dominate this accident class are those in which equipment damaged as a result of the fire affects the operation of one or more trains of component cooling and charging. The affected equipment can include support systems such as electrical distribution and cooling water. The dominant fire area in this accident class is assumed to result in failures of injection systems in addition to seal cooling (Auxiliary Building Ground Floor). This accident sequence would result in a high pressure melt ejection without RWST water. Short-term challenges to containment would include DCH, hydrogen combustion and steam explosions. As noted before, the magnitude of containment challenge for these phenomena was evaluated in the internal events PRA and found to have limited consequences on containment.

The remaining two areas that dominate this accident class include Train A 4kV and 480V switchgear. SI is assumed to fail as a result of a combination of fire damage as well as random failures. However, on vessel penetration and depressurization, RHR and containment spray are available to provide short-term debris cooling. Similar to the Aux Building Ground Floor, the short-term challenges to containment include DCH, hydrogen combustion and steam explosions, which were evaluated as a part of the internal events PRA.

Long-term challenges for this accident class are dominated by gradual pressurization of containment from steam or noncondensible gas generation. No new challenges to containment are identified that were not previously evaluated as a part of the internal events PRA.

Table B.2.12–1 Prairie Island Fire IPEEE Level 1 to Level 2 Dependencies

Fire Area	Secondary Cooling		Debris Cooling						Containment Control		
			Injection			Recirculation					
	AFW	MFW	SI	RHR	CS[3]	SI Recirc	RHR Recirc	CS Recirc	RHR	RCU	CS[3]
Class TEH											
Control Room (13)[1]	–	–	✓	✓	✓	✓[5]	✓[5]	✓[5]	✓	✓	✓[5]
Relay Room (18)[1]	–	–	✓	✓	✓	✓[5]	✓[5]	✓[5]	✓	✓	✓[5]
480V Swgr-Bus 121 (22)	–	–	–	✓	✓	–	✓	✓	✓	✓	✓
AFW/Air Comp (31)	–	–	✓	✓	✓	✓	✓	✓	✓	✓	✓
Aux Bldg Ground Floor (58)	–	–	–	–	–	–	–	–	–	✓	–
TB Ground & Mez (69)	–	–	–	✓	✓	–	–	✓	✓	✓	✓
Class TLH											
Control Room (13)[2]	–	–	4	4	✓	–	✓[6]	✓[6]	✓[6]	✓	✓[6]
Relay Room (18)[2]	–	–	4	4	✓	–	✓[6]	✓[6]	✓[6]	✓	✓[6]
TB Ground & Mez (69)	–	–	4	4	✓	–	✓[6]	✓[6]	✓[6]	✓	✓[6]
Class SEH											
Aux Bldg Ground Floor (58)	✓	–[7]	–	–	–	–	–	–	–	✓	–
480V Swgr–Bus 111 (80)	✓	–[7]	–[7]	✓	✓	–	–	–	–	–[7]	–
4kV Swgr–Bus 15 (81)	✓	–[7]	–[7]	✓	✓	–	–	–	–	–[7]	–

✓ Available post-core damage.

– Failed as a part of Level 1 accident sequences (random or fire related).

1 Dominated by unsuccessful fire suppression.

2 Fire successfully suppressed.

3 Containment spray recirc is available but not proceduralized.

4 Suceeded as part of Level 1 accident sequences.

5 Must be aligned locally.

6 Provided the reason for recirculation failure was not RHR.

7 Random failures in Cooling Water are required in addition to fire damage.

B.2.13 Treatment of Fire Risk Scoping Study Issues

NRC Generic Letter 88/20, Supplement 4 lists the following fire risk scoping study issues to be addressed in IPEEE fire analyses:

1. Seismic/fire interactions,
2. Fire barrier assessment,
3. Effectiveness of manual fire fighting,
4. Effects of fire suppressants on safety equipment (total environment equipment survival), and
5. Control systems interactions.

The specific concerns regarding each of these issues are discussed in the FIVE methodology. This methodology was used as guidance for evaluating each of the issues. Where appropriate, relevant fire risk scoping study issues have been incorporated into other phases of this study, such as the area screening and the detailed fire scenario evaluation.

Review of the fire risk scoping study issues resulted in the conclusion that these issues are not significant contributors to fire-induced core damage at Prairie Island.

The evaluation of each fire risk scoping study issue is discussed below.

B.2.13.1 Seismic/Fire Interactions

This issue involves three concerns: seismically induced fires, seismically induced actuation of fire protection systems, and seismically induced degradation of fire suppression systems.

Seismically Induced Fires

In general, earthquakes are not known to cause fires in industrial facilities [12]. However, the potential failure of vessels containing flammable or combustible liquids or gases could cause a fire hazard in the plant following an earthquake. As a part of the seismic walkdowns, a survey of tanks and vessels that may contain flammable fluids was performed. Day tanks for the diesel generators and diesel cooling water pumps were found to be adequate in the seismic IPEEE (see Appendix A of the IPEEE report). The fire areas containing flammable liquids that were not seismically screened are:

Fire Area	Description	Flammable Gas or Liquid
8	Turbine Deck	H_2 T/G Oil
24	Admin Building Oil Storage	T/G Oil
41B	Screenhouse Basement	Diesel Fire pump fuel oil day tank
57	Gas House	H_2 Bottles
69	Turbine Building Ground & Mezzanine Floor, Unit 1	T/G Oil, T/G H_2
70	Turbine Building Ground & Mezzanine Floor, Unit 2	T/G Oil, T/G H_2

Of these, the fire evaluations indicate that only Areas 69 and 70 are of concern if a fire occurs in those areas. The other areas contain little or no safe shutdown equipment, and substantial equipment will remain unaffected by the fire to enable shutdown.

For Fire Areas 69 and 70, the seismic/fire interaction was evaluated by assuming that a seismic event occurs of sufficient magnitude to result in a loss of offsite power. In addition, it is assumed for evaluation purposes that a fire starts (the combustible material is the flammable gas or liquid) and spreads without being suppressed. Each of these areas is a part of a burn sequence (Burn Sequences 69 and 70), comprised of other fire areas in addition to the area containing the flammable gas/liquid (see Table B.2.6.3). Thus, under the assumptions being employed, it is possible for equipment not located specifically in Fire Area 69 or 70 to be disabled by the fire.

For Burn Sequence 69 (starting in Fire Area 69), the combination of an unsuppressed fire and a loss of offsite power (LOOP) results in failures of:

- #11 AFW pump (fire)
- #11 CL pump (fire and/or LOOP)
- #12 CL pump (ventilation/air damper #11 failure due to fire)
- #21 CL pump (LOOP—Bus 23)
- #22 CL pump (ventilation/air damper #21 failure due to fire)
- #11 and #13 CVCS pumps (#11 pump cable, #13 pump cable, #1K2 bus)
- Train B SI (due to loss of CL pumps)

Remaining equipment unaffected by the fire or LOOP event includes:

- #12 AFW pump
- Ability to crosstie to #21 AFW pump
- #121 CL pump
- #12 CVCS pump
- Train A SI

The amount of equipment still available is sufficient for safe shutdown in response to the combined seismic/fire event. If a small LOCA also occurs, an SI pump would be available as noted above.

For Burn Sequence 70 (initiated in Fire Area 70), the LOCA/unsuppressed fire combination results in failures of:

- #11 CL pump (LOOP)
- #21 CL pump (LOOP)
- D6 DG

Remaining equipment unaffected by the fire or LOOP event includes:

- D5 DG
- All AFW pumps (including the crosstie from Unit 2)
- CL pumps #121, #122, #22
- SI pumps, both trains
- CVCS pumps, all pumps

The remaining equipment is sufficient for safe shutdown; LOCA concerns are not important for this sequence due to the availability of SI.

Actions not incorporated into this evaluation which could be taken, if necessary, to reduce the potential CDF include:

- Credit for suppression (manual fire fighting)
- Credit for curbs to contain lube oil
- Assessment of the potential for ignition given a loss of offsite power
- Additional seismic evaluation of flammable storage containers (to determine seismic ruggedness and reduce conditional failure probability given a seismic event)

<u>Seismic Actuation of Fire Suppression Systems</u>

The NRC's information notice 94-12 notes that (1) mercury relays are susceptible to seismic actuation, (2) smoke detectors could be actuated by dust rising during a seismic event, and (3) unprotected essential components could be damaged by spray from deluge systems. Mercury relays and fire suppression equipment actuated by smoke detectors (except for exterior transformer deluge) are not used for fire protection of essential equipment considered in the Prairie Island IPEEE.

Of the important plant areas containing essential equipment considered in the seismic IPEEE, only the AFW pump rooms are protected by fire water systems. Loss of essential equipment in these areas due to inadvertent actuation of the fire water system by a seismic event is considered highly unlikely. Actuation of the system requires failure of the fusible links in the sprinkler heads. No mechanism was identified that could cause failure of these fusible links during a seismic event. Also, as discussed previously (for inadvertent actuation), failure of multiple systems would require the actuation of multiple sprinkler heads.

Seismic Degradation of Fire Protection Systems

During an earthquake, fire suppression systems could disable nearby safe shutdown components either by colliding with them, or by bursting and either spraying or flooding the equipment. Such interactions were investigated as a part of the seismic walkdowns. Spray or flooding of essential components due to actuation of fire water systems is considered unlikely, as discussed above. No potential for failure of essential equipment due to collision with fire protection systems was identified in the seismic walkdown.

B.2.13.2 Fire Barrier Effectiveness

Fire barriers are used at Prairie Island to provide physical separation of redundant trains of safe shutdown equipment. Qualification of these barriers must be maintained to ensure an effective fire protection program. A series of detailed barrier inspection procedures are implemented to inspect all fire area boundaries for the express purpose of protecting safe shutdown equipment. Fire barrier inspection procedures require that every square inch of every boundary be inspected, including penetration seals and fire dampers. Fire doors are inspected and maintained per procedure. All fire barrier inspections are performed on an eighteen-month interval.

In addition to inspection of the fire area boundaries required by Appendix R, certain boundaries are also inspected per previous NRC commitments and/or good fire protection practices. Other fire barrier concerns such as fire damper operability, as outlined in NRC information notices 83-69 and 89-52, have been resolved with walkdowns or inspections, or by modifying the operating procedures. This detailed inspection and maintenance program ensures that all fire boundaries are adequate and in good repair. Fire barrier effectiveness is ensured by implementation of these procedures.

B.2.13.3 Effectiveness of Manual Fire Fighting

NUREG/CR-5088, "Fire Risk Scoping Evaluation" [11], identified six components of an effective manual fire fighting program: (1) fire reporting, (2) fire brigade personnel and equipment, (3) fire brigade training, (4) fire brigade practice, (5) fire brigade drills, and (6) record keeping on fire brigade members. NSP's fire fighting procedures, training, and administrative work instructions address all six of these issues.

Fire reporting is accomplished with two-way radios carried by the operators and staged with the fire brigade equipment, or via phone lines designated for that purpose. Use and staging of this equipment is detailed in plant procedures. Adequate staffing is considered to consist of six operating shift fire brigades of five people each; three of whose members must be operations personnel. Supporting equipment is prestaged in the fire brigade equipment room and includes personal protective equipment, communications equipment, portable lights and ventilation, etc.

Course work associated with fire brigade training covers subjects ranging from basic principles of fire chemistry and physics to more advanced subjects including evaluation of fire hazards and fighting fires in confined areas. All fire brigade members receive hands-on fire fighting training

at least once per year to provide experience in actual fire extinguishment and the use of emergency breathing apparatus. Fire brigade drills are performed in the plant so that each fire brigade shift can practice as a team. Backshift drills and unannounced drills are performed for each brigade at least once per year.

Detailed training records and periodic quality assurance audits of the fire protection program assess the adequacy of the fire brigade training. Audit reports are kept on file at the plant.

Based on an examination of Prairie Island's established fire fighting training program, the attributes of an adequate fire protection program related to manual fire fighting identified in NUREG/CR-5088 are satisfied. The plant's fire brigade and manual fire fighting capability is therefore considered to be effective. Section B.2.8 describes how manual fire fighting is accounted for in this study.

B.2.13.4 Total Environment Equipment Survival

This issue includes the following three concerns:

(a) The potential for adverse effects on plant equipment caused by combustion products released from the fire causing damage to, and possible loss of, safe shutdown function.

(b) The spurious or inadvertent actuation of fire suppression systems resulting in the loss of safe shutdown functions.

(c) Operator effectiveness in performing manual safe shutdown actions and potentially misdirected suppression effects in smoke-filled environments.

With the exception of the Control and Relay Rooms, all fire initiators included in the accident sequence quantification are assumed to spread and engulf the entire sub-area in which they are assumed to occur. Smoke effects on equipment located in these spaces is not an issue because the equipment is assumed to be destroyed by the fire. Equipment in adjoining spaces is unlikely to be damaged because the barriers that prevent the fire spread will, in most cases, also limit smoke propagation. Smoke that does propagate to other spaces will be dissipated. In addition, the FIVE methodology does not currently evaluate non-thermal environmental effects of smoke on equipment because the detrimental effects of smoke on equipment are not believed to be significant.

The plant design philosophy is to avoid damage to safe shutdown equipment by inadvertent actuation of the fire protection equipment. Deluge valves that protect safety related equipment are preaction type. The exception to this philosophy is the auxiliary feedwater pump room, which has a wet pipe system expanded to add sprinkler heads below congested areas. Unit specific pumps are located in separate rooms so that actuation in one room would not affect the redundant train of the same unit. The Fire Detection System provides the Control Room operator with status indication of automatically-actuated suppression systems thus permitting appropriate action in the event of inadvertent actuation. Manual shutoff valves are provided to terminate

system operation. Susceptibility of multiple trains of safe shutdown equipment to spurious actuation of suppression systems is not expected in any case.

Manual actions to operate equipment outside of the Control Room or HSDPs are not given significant credit in this study. Manual response to fires inside the Control Room is discussed in Section B.2.8. Review of the heating, ventilation, and air conditioning systems determined that sufficient ventilation is available to prevent excessive smoke propagation between systems and structures. Emergency lighting is positioned throughout the plant and self-contained breathing apparatus equipment is also staged at appropriate locations in the plant. This equipment allows the fire fighter to effectively combat any fire.

B.2.13.5 Control Systems Interactions

Control system interactions following a fire is principally a concern at facilities without a remote shutdown capability. Installation of the hot shutdown system panels resolved this issue at the Prairie Island station. These panels allow the operators to remotely control at least one train of safe shutdown equipment from the auxiliary feedwater pump rooms.

One of the primary features of these panels is that cables for equipment controlled from this location can be completely isolated from the Control and Relay Rooms. This feature allows remote operation of the equipment regardless of the condition of these rooms. The Prairie Island operations manual provides the necessary guidance to control the plant from these panels. In addition to the written guidance, all tools and equipment required to implement the actions are staged near the panels.

B.2.14 USI A-45 and Other Safety Issues

The Prairie Island fire IPEEE is an integrated look at core damage risk for internal fires and includes potential impacts from loss of decay heat removal. The IPEEE used a systematic approach to evaluate plant systems and components looking for vulnerabilities during a fire or precipitated by a fire. Inherent to this approach is an evaluation of the potential for loss of decay heat removal capability.

NUREG-1289 "Unresolved Safety Issue A-45, Shutdown Decay Heat Removal Requirements", Section 1.1, lists two criteria that must be met by systems that are used to remove decay heat. These criteria are (1) to maintain water inventory to the RCS to ensure adequate cooling to the fuel and (2) to provide the means for transferring decay heat from the reactor coolant system to an ultimate heat sink. With this definition in mind, NSP chose to define DHR as decay heat removal from the reactor core.

There are four possible methods of removing decay heat from the core at Prairie Island. These consist of:

1. Secondary cooling through the steam generators with main feedwater and auxiliary feedwater providing steam generator makeup.

2. Bleed and feed cooling utilizing the SI pumps and pressurizer PORVs.

3. Reactor coolant system injection and recirculation as provided by the SI and RHR systems during medium and large LOCAs. (Note: No fire is postulated that will lead to a medium or large LOCA. A medium or large LOCA occurring simultaneously with a fire is considered probabilistically insignificant.)

4. Shutdown cooling mode of RHR operation after the reactor coolant system has been cooled down and depressurized to RHR shutdown cooling conditions.

Secondary cooling through the steam generators is the preferred means of removing decay heat during normal shutdown until reactor pressure drops to the point where RHR shutdown cooling can be placed in service. Steam relief was not modeled for the Prairie Island IPEEE because of the many diverse means of steam removal. Because of the many and diverse means of steam relief, it was assumed that loss of steam generator cooling would be dominated by loss of makeup capability. There are two means of makeup to the SGs that were modeled in the Prairie Island fire IPEEE; auxiliary feedwater (AFW) and main feedwater (MFW).

If secondary cooling is unavailable, bleed and feed cooling utilizing the SI pumps and pressurizer PORVs is directed. To perform decay heat removal via bleed and feed, the operators inject cool water to the reactor coolant system with the SI system and remove hot water from the reactor coolant system through the pressurizer PORVs. SI injection in this mode maintains adequate reactor coolant system inventory as well as provides decay heat removal.

The shutdown cooling mode of RHR operation is initiated after the RCS has been cooled down and depressurized to RHR shutdown cooling conditions. In this mode of operation, the RHR pumps draw suction from the Loop A and B hot legs and discharge the coolant through the RHR heat exchangers and back to the RCS Loop B cold leg. The heat load of the coolant is transferred to the component cooling water system from the RHR heat exchangers. The SDC mode of RHR operation can only be entered after the RCS has been cooled and depressurized to 350°F and 425 psig.

Given that NSP chose to define DHR as decay heat removal from the reactor core, loss of DHR becomes synonymous with core damage as there are no Level 1 core damage sequences that do not involve loss of either one or both of the two requirements identified in NUREG-1289. As identified above, there are many redundant and diverse means for DHR at Prairie Island. Multiple DHR systems and operator actions would have to fail in combination to have an impact on the DHR capability at Prairie Island. Additionally, there is no area in the plant in which a fire would lead directly to the inability to cool the core. Without additional random equipment failures unrelated to damage caused by the fire, core damage will not occur. With the overall fire induced CDF being an acceptably low level of <7E-5/yr, NSP considers it has fulfilled the requirements of USI A-45 with respect to fire events.

B.2.15 Results and Conclusions

B.2.15.1 Summary of Results

The total vulnerability due to fires at Prairie Island is calculated to be less than 7E-5 core damage events per year. These results are summarized by fire area in Table B.2.11.1. More than 95% percent of the plant risk associated with internal fires can be traced to nine rooms/burn sequences. These rooms/burn areas consist of the Auxiliary Building 695' elevation, the 480V safeguards Bus 121 room, the Turbine Building Ground and Mezzanine Floors, the Relay Room, the 4160V safeguards Bus 15 room, the 480V safeguards Bus 111 room, the Trains "A" and "B" Hot Shutdown Panel and Air Compressor/AFW Rooms, and the Control Room.

B.2.15.2 Conclusions and Recommendations

The results of the fire IPEEE accident sequence quantification were derived using a methodology that includes a number of conservative assumptions. Fires were assumed to spread until they completely engulfed the sub-area in which they started. In addition, with the exception of the main Control Room, the Relay Room, and the auxiliary feedwater pump area, the effects of fire suppression were not credited. No repair actions were applied to any accident sequence even if the equipment was not in the area affected by the fire. Therefore this methodology, while demonstrating relatively low risk due to internal fires, yields conservative core damage frequencies.

The relatively low plant risk due to fires is in large part due to Prairie Island's implementation of the requirements of 10CFR50, Appendix R. These requirements, including separation of alternate or redundant trains of safe shutdown equipment, installation of fire barriers, and an installation of an alternate shutdown system outside the Control and Relay Rooms, combine to limit the total risk due to fires. The administrative control of transient combustibles also contributes to the low fire risk.

B.2.16 References

1. Generic Letter No. 88-20, Supplement 4, "Individual Plant Examination Of External Events (IPEEE) for Severe Accident Vulnerabilities", United States Nuclear Regulatory Commission, June 1991.

2. Prairie Island Nuclear Generating Plant Individual Plant Examination (IPE), NSPLMI-94001, Rev. 0, Northern States Power Company, February, 1994.

3. Safe Shutdown Analysis Engineering Report - Prairie Island Nuclear Generating Plant, Rev.2, Northern States Power Company, February 1991.

4. Fire Induced Vulnerabilities Evaluation (FIVE) Plant Screening Guide, EPRI, September 1991.

5. NUREG/CR-4527/1 of 2, "An Experimental Investigation of Internally Ignited Fires In Nuclear Power Plant Control Cabinets: Part 1: Cabinet Effect Tests," U.S. Nuclear Regulatory Commission, April 1987.

6. [DELETED]

7. Updated Fire Hazards Analysis - Prairie Island Nuclear Generating Plant, Rev.7, Northern States Power Company, January 1990.

8. "Fire Events Database for U.S. Nuclear Power Plants," NSAC-178L, June 1992.

9. Appendix III, Table III 5-3, "Reactor Safety Study: An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," WASH-1400, 1975.

10. "Report on Full-Scale Horizontal Cable Tray Fire Tests," FNAL-TM-1549, Fermi National Accelerator Laboratory, September 1989.

11. NUREG/CR-5088, "Fire Risk Scoping Study: Investigation of Nuclear Power Plant Fire Risk, Including Previously Unaddressed Issues," NRC, January 1989.

12. EPRI NP-6041, "A Methodology for Assessment of Nuclear Power Plant Seismic Margin", Rev. 1, EPRI, July 1991.

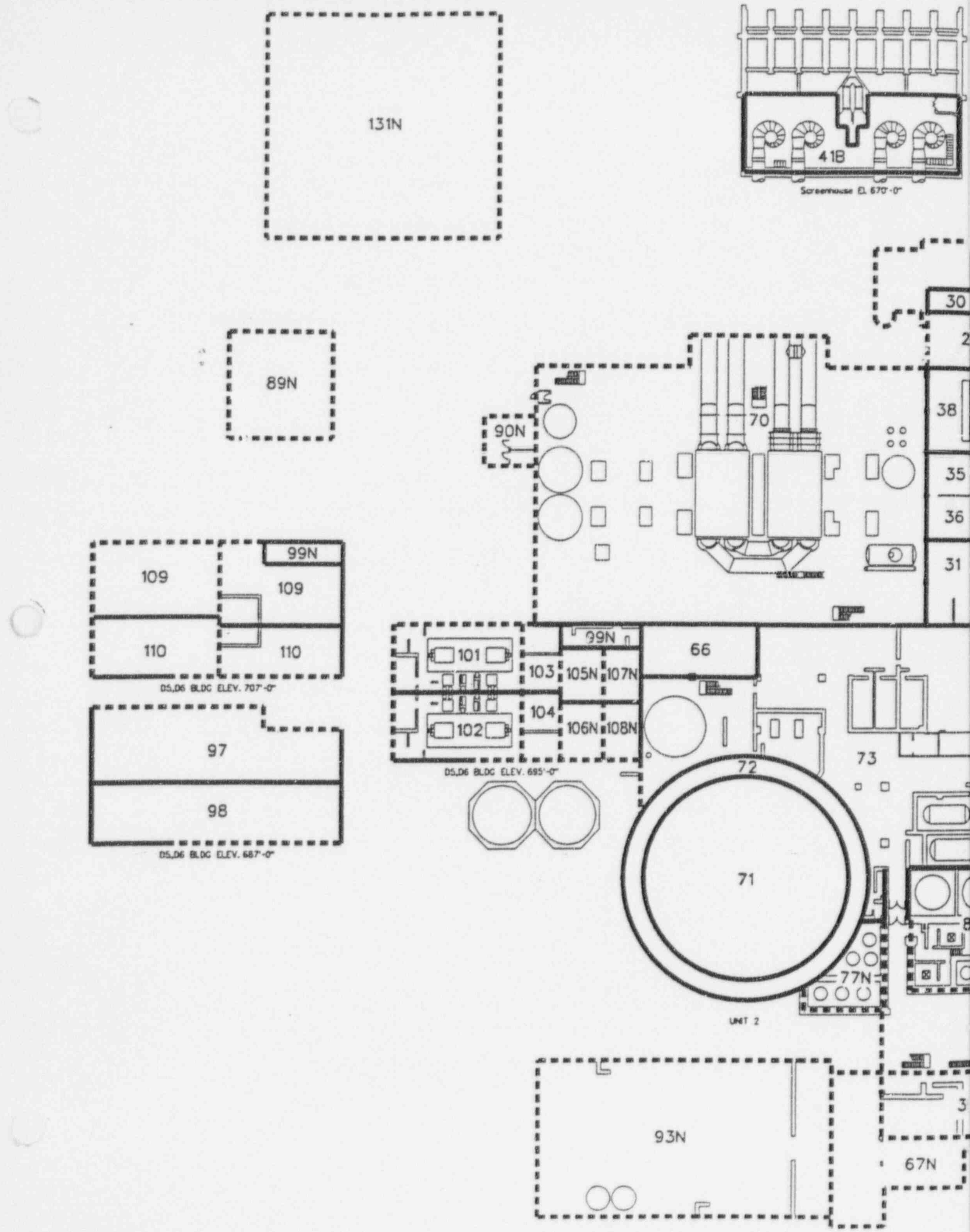
Prairie Island
Individual Plant Examination
of External Events (IPEEE)

Appendix B

Internal Fires Analysis

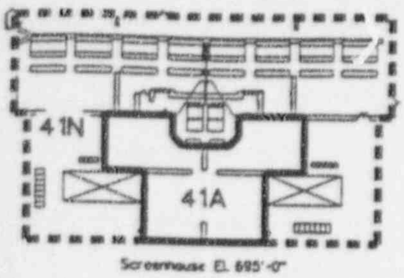
Attachment 1

Selected floor plans from the Updated Fire Hazards Analysis
Pages: 1 through 4 of Figure 1.1-1

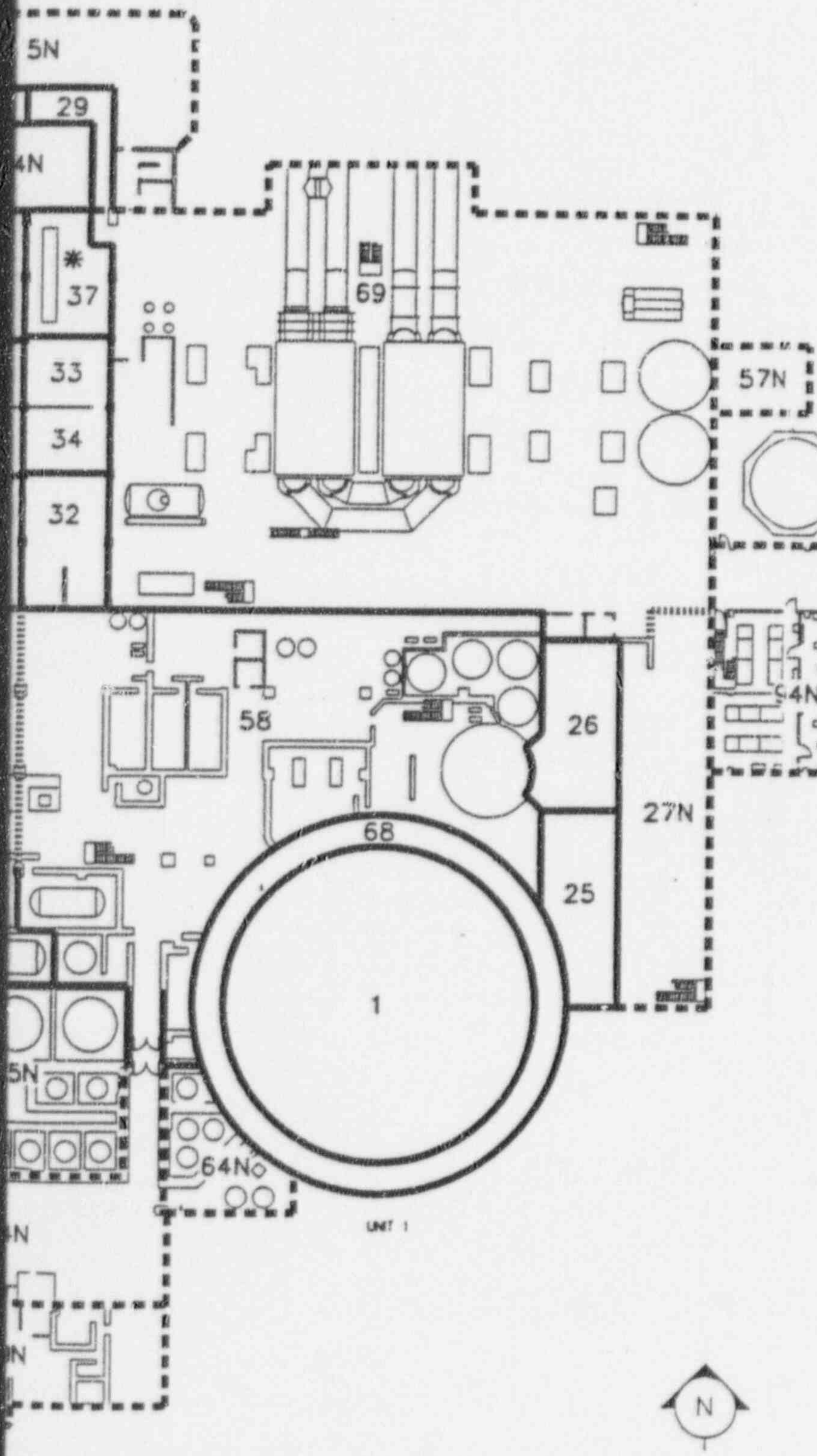

131N
41B
Screenhouse EL 670'-0"
30
89N
90N
70
38
35
36
31
109
99N
109
110
110
D5,D6 BLDG ELEV. 707'-0"
99N
101
66
103
105N
107N
104
106N
108N
102
D5,D6 BLDG ELEV. 685'-0"
73
72
97
98
D5,D6 BLDG ELEV. 687'-0"
71
77N
UNIT 2
93N
67N

UPDATED P.I. OPNS

El. 695'



Screenhouse El. 695'-0"



LEGEND

1- CONTAINMENT UNIT 1
4N- FUEL HANDLING AREA
5N- OLD ADMINISTRATION BLDG.
24N- OIL STORAGE AREA
25- DIESEL GEN ROOM 1
26- DIESEL GEN ROOM 2
27N- WATER CONDITIONING EQUIP AREA
29- ADMIN BLDG ELEC & PIPING RM 1
30- ADMIN BLDG ELEC & PIPING RM 2
31- 'A' TRAIN HOT SHUTDOWN PANEL & AIR COMP./ AUX FEEDWATER ROOM
32- 'B' TRAIN HOT SHUTDOWN PANEL & AIR COMP./ AUX FEEDWATER ROOM
33- BATTERY ROOM 11
34- BATTERY ROOM 12
35- BATTERY ROOM 21
36- BATTERY ROOM 22
37- UNIT 1 480V NORMAL SWGR ROOM
38- UNIT 2 480V NORMAL SWGR ROOM
39N- RADWASTE BLDG
41N- SCREENHOUSE (GENERAL AREA)
41A- SCREENHOUSE DDCWP AREA
41B- SCREENHOUSE BASEMENT
57N- HYDROGEN HOUSE
58- AUX BLDG GROUND FLOOR UNIT 1
64N- AUX BLDG LOWER LEVEL DECAY AREA UNIT 1
66- STORAGE ROOM
67N- RESIN DISPOSAL AREA
68- CONTAINMENT ANNULUS UNIT 1
69- TURB BLDG GROUND FLR & MEZZ FLR UNIT 1
70- TURB BLDG GROUND FLR & MEZZ FLR UNIT 2
71- CONTAINMENT UNIT 2
72- CONTAINMENT ANNULUS UNIT 2
73- AUX BLDG BASEMENT UNIT 2
77N- AUX BLDG LOW LEVEL DECAY AREA UNIT 2
85N- HOLDUP TANK/ DEMINERALIZER AREA
89N- GUARD HOUSE
90N- EMERGENCY GENERATOR BUILDING
93N- DRUM STORAGE AREA (LOW LEVEL RAD WASTE)
94N- SERVICE BLDG / COMPUTER SWGR ROOM
97- D5 BASEMENT
98- D6 BASEMENT
99N- D5, D6 BLDG. STAIRWELL
100- #21 D5/D6 FUEL OIL RECEIVING TANK
101- D5 ENGINE ROOM
102- D6 ENGINE ROOM
103- D5 CONTROL ROOM
104- D6 CONTROL ROOM
105N- D5 BATTERY ROOM
106N- D6 BATTERY ROOM
107N- D5 INVERTER ROOM
108N- D6 INVERTER ROOM
109- D5 CABLE TRAY AREA, GROUNDING CABINET AND MCC-2081 ROOMS
110- D6 CABLE TRAY AREA, GROUNDING CABINET AND MCC-2082 ROOMS
131N- NEW ADMIN BLDG

XX - FIRE AREA.

XXN - FIRE AREA CONTAINING NO SAFE SHUTDOWN EQUIPMENT.

- T.S.-3.14 BOUNDARIES (NUCLEAR SAFE SHUTDOWN) 10CFR50 .APP.R (AREAS CONTAINING EQUIPMENT NECESSARY FOR SAFE SHUTDOWN DUE TO FIRE.

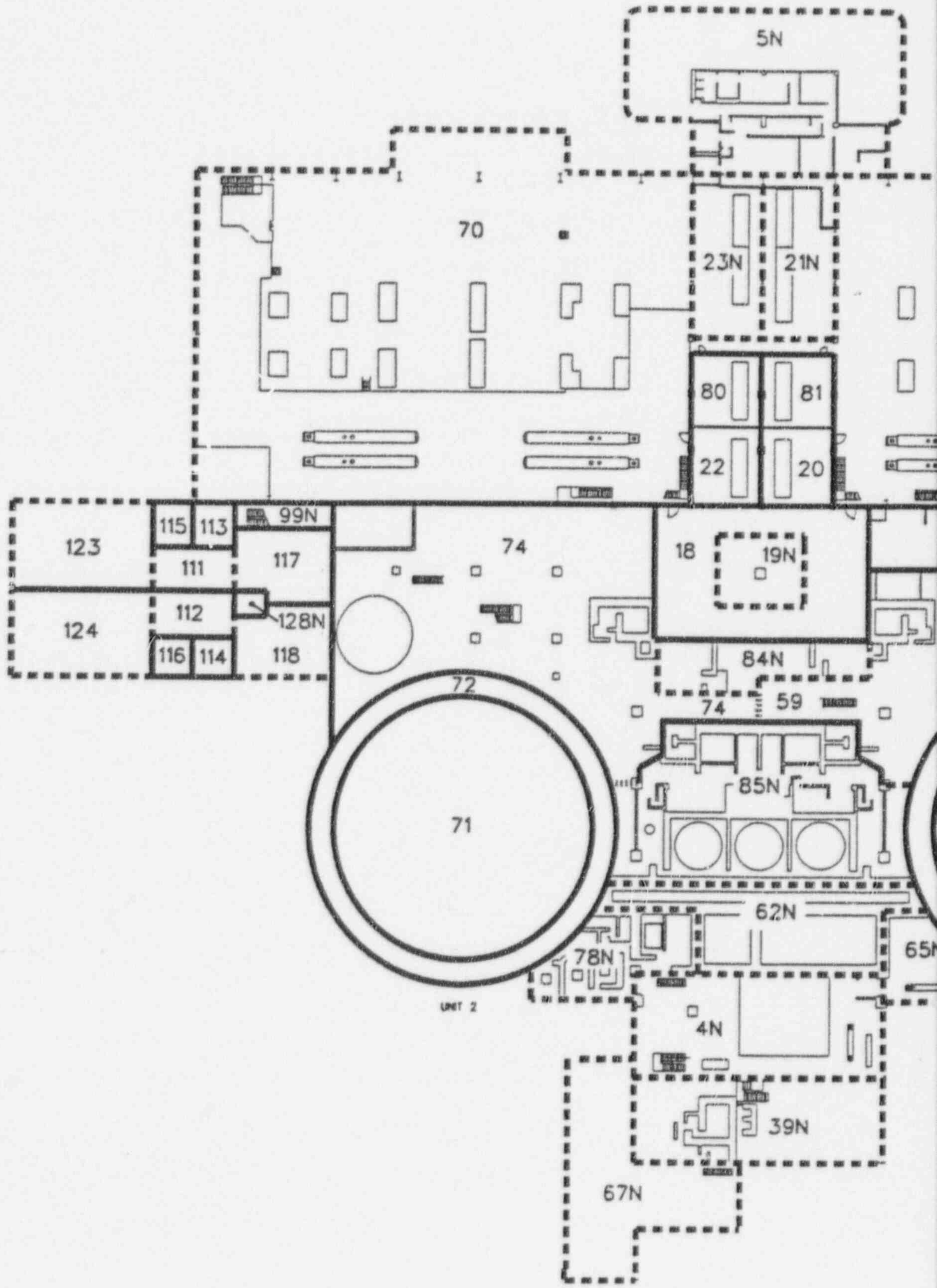
- GENERAL FIRE BOUNDARIES FOR BALANCE OF PLANT AND NON 3-HOUR BARRIERS.

- FIRE AREA BOUNDARY (FREE AIR SPACE).

* - 10CFR50 APP. R BOUNDARIES ONLY.

Figure 1.1-1
Sheet 1 of 5

9612240185-01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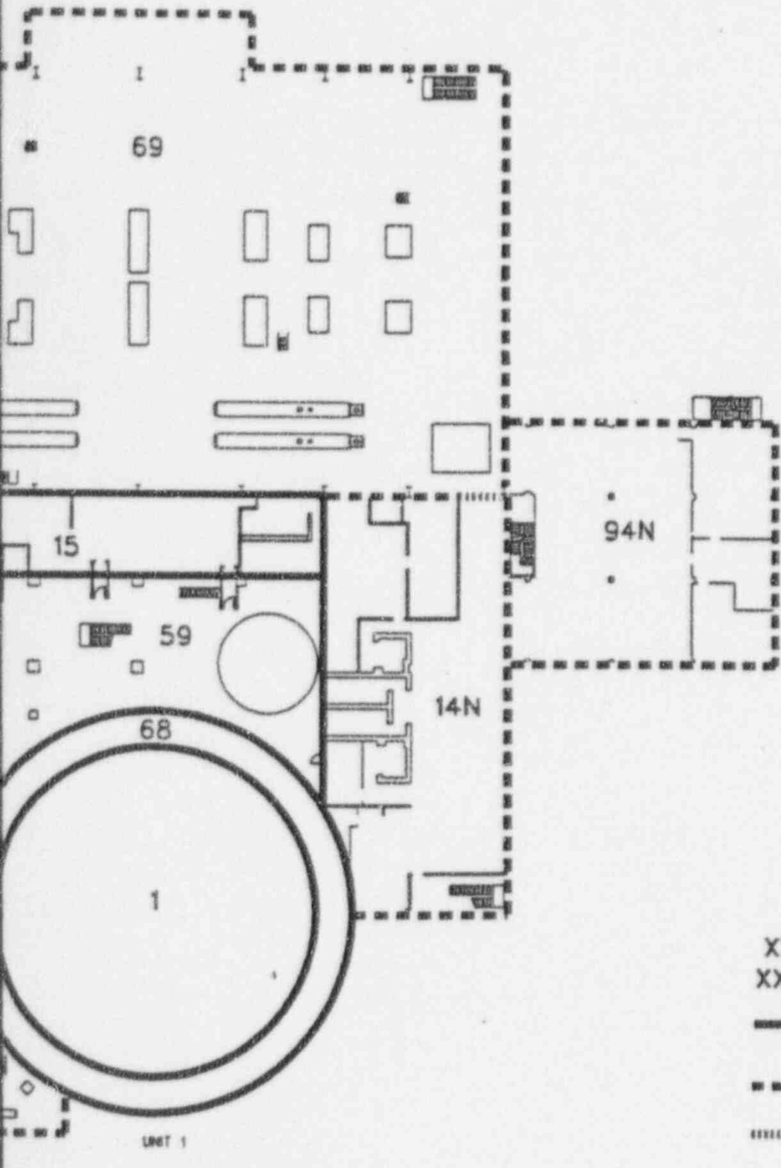
70
23N
21N
80
81
22
20
99N
115
113
123
111
117
74
18
19N
112
128N
124
116
114
118
84N
72
74
59
85N
71
62N
78N
65N
UNIT 2
4N
39N
67N

El. 715'



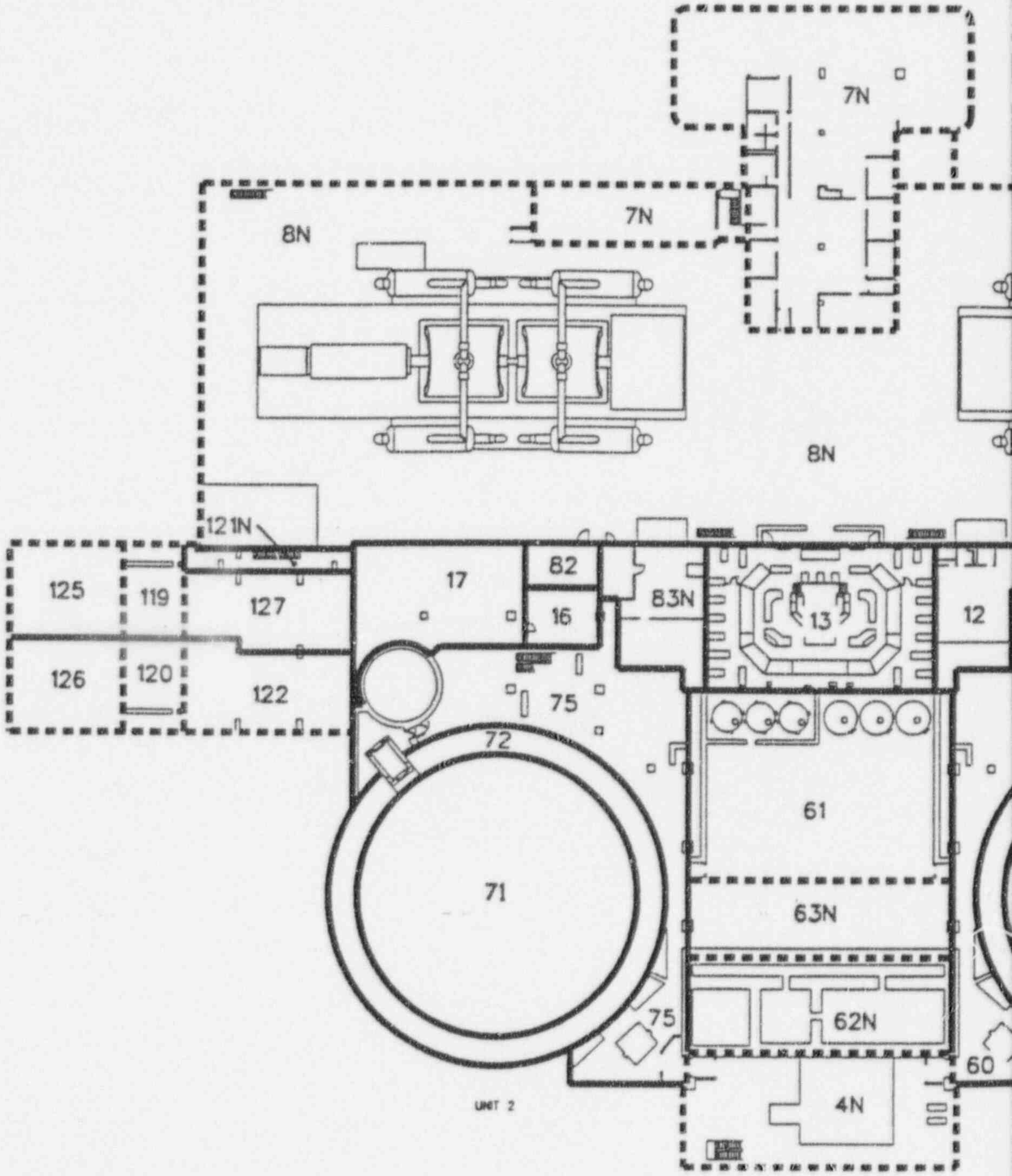
LEGEND

1- CONTAINMENT UNIT 1
4N- FUEL HANDLING AREA
5N- OLD ADMINISTRATION BLDG.
14N- WORKING MATERIAL AND LUNCH ROOM
15- ACCESS CONTROL
11- RELAY & CABLE SPREADING RM UNITS 1 & 2
19N- COMPUTER ROOM
20- UNIT 1 4.16KV SAFEGUARDS SWGR (BUS 16)
21N- UNIT 1 4.16KV NORMAL SWGR (BUS 13 & 14)
22- UNIT 1 480V SAFEGUARDS SWGR (BUS 121)
23N- UNIT 2 4.16KV NORMAL SWGR (BUS 23 & 24)
39N- RADWASTE BLDG
59- AUX BLDG MEZZ LEVEL UNIT 1
62N- SPENT FUEL POOL AREA
65N- SPENT FUEL POOL HEAT EXCHANGERS & PUMPS
67N- RESIN DISPOSAL AREA
68- CONTAINMENT ANNULUS UNIT 1
69- TURBINE BLDG GROUND & MEZZ FLRS UNIT 1
70- TURBINE BLDG GROUND & MEZZ FLRS UNIT 2
71- CONTAINMENT UNIT 2
72- CONTAINMENT ANNULUS UNIT 2
74- AUX BLDG MEZZ LEVEL UNIT 2
78N- WASTE GAS COMPRESSOR AREA
80- 480V SWGR ROOM (BUS 111)
81- 4.16KV SWGR ROOM (BUS 15)
84N- COUNTING ROOM AND LABS
85N- HOLDUP TANK / DEMINERALIZER AREA
94N- SERVICE BLDG / COMPUTER ROOM
99N- STAIRWELL
111- D5 KNOB ROOM
112- D6 KNOB ROOM
113- 21 D5 F.O. DAY TANK ROOM
114- 22 D6 F.O. DAY TANK ROOM
115- 21 D5 L.O. M-U ROOM
116- 22 D6 L.O. M-U ROOM
117- 4 KV BUS 25,MCC-2TA1 ROOM
118- 4 KV BUS 26,MCC 2TA2 ROOM
123- D5 RADIATOR ROOM
124- D6 RADIATOR ROOM
128N- 4KV BUS 27 ROOM

XX - FIRE AREA.
XXN - FIRE AREA CONTAINING NO SAFE SHUTDOWN EQUIPMENT.
▬▬▬ - T.S.-3.14 BOUNDARIES (NUCLEAR SAFE SHUTDOWN) 10CFR50 APP. R (AREAS CONTAINING EQUIPMENT NECESSARY FOR SAFE SHUTDOWN DUE TO FIRE.
■ ■ ■ - GENERAL FIRE BOUNDARIES FOR BALANCE OF PLANT AND NON 3-HOUR BARRIERS.
IIIIIIII - FIRE AREA BOUNDARY (FREE AIR SPACE).

Figure 1.1-1
Sheet 2 of 5

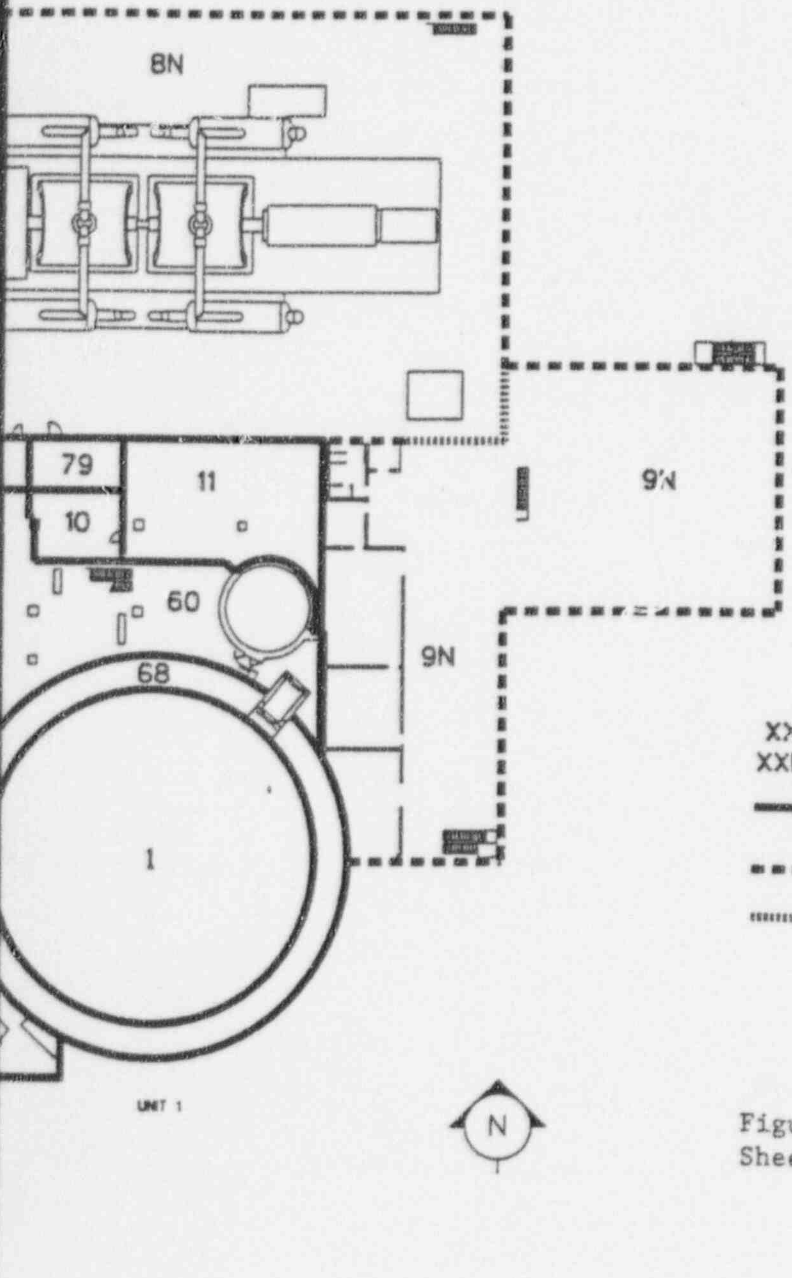
9612240185-02



7N
7N
8N
8N
121N
125
119
127
17
82
16
83N
13
12
126
120
122
75
72
61
71
63N
75
62N
60
4N
UNIT 2

UPDATED P.I. OPNS

El. 735'



LEGEND

1- CONTAINMENT UNIT 1
4N- FUEL HANDLING AREA
7N- OLD ADMIN BLDG OFFICE AREA
8N- TURBINE DECK (UNITS 1 & 2)
9N- MAINTENANCE SHOP
10- "A" TRAIN EVENT MONITORING RM.
11- UNIT 1 NORMAL SWGR & CONTROL ROD DRIVE RM.
12- OSC ROOM
13- CONTROL ROOM
16- "B" TRAIN EVENT MONITORING RM.
17- UNIT 2 NORMAL SWGR & CONTROL ROD DRIVE RM.
60- AUX BLDG OPERATING LEVEL UNIT 1
61- AUX BLDG ANTI "C" CLOTHING AREA
62N- SPENT FUEL POOL AREA
68- CONT. ANNULUS UNIT 1
72- CONT. ANNULUS UNIT 2
75- AUX BLDG. OPER. LEVEL UNIT 2
79- 480V SFGD SWGR ROOM (BUS 112)
112- 480V SFGD SWGR ROOM (BUS 122)
113N- OPERATORS LOUNGE
119- *21 D5 HT/LT CLNT MU TANK PUMP RM
120- *22 D6 HT/LT CLNT MU TANK PUMP RM
121N- D5,D6 BLDG STAIRWELL
122- 480V SWGR 221 & 222 BUS RM
125- D5 FAN ROOM
126- D6 FAN ROOM
127- 480V SWGR ROOM 211 & 212

XX - FIRE AREA.

XXN - FIRE AREA CONTAINING NO SAFE SHUTDOWN EQUIPMENT.

- T.S.-3.14 BOUNDARIES (NUCLEAR SAFE SHUTDOWN) 10CFR50 APP. R (AREAS CONTAINING EQUIPMENT NECESSARY FOR SAFE SHUTDOWN DUE TO FIRE.

- GENERAL FIRE BOUNDARIES FOR BALANCE OF PLANT AND NON 3-HOUR BARRIERS.

- FIRE AREA BOUNDARY (FREE AIR SPACE).

Figure 1.1-1
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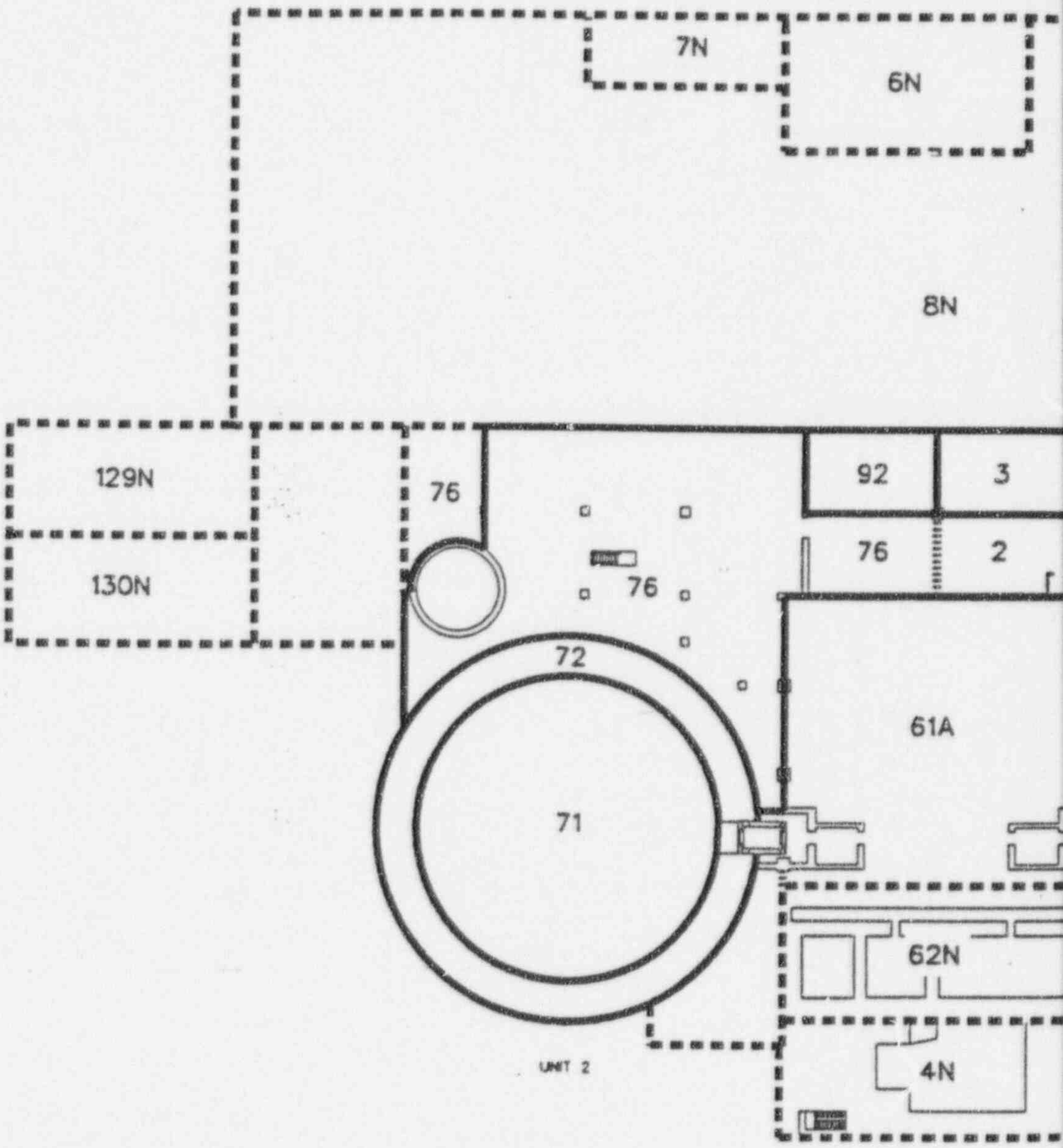
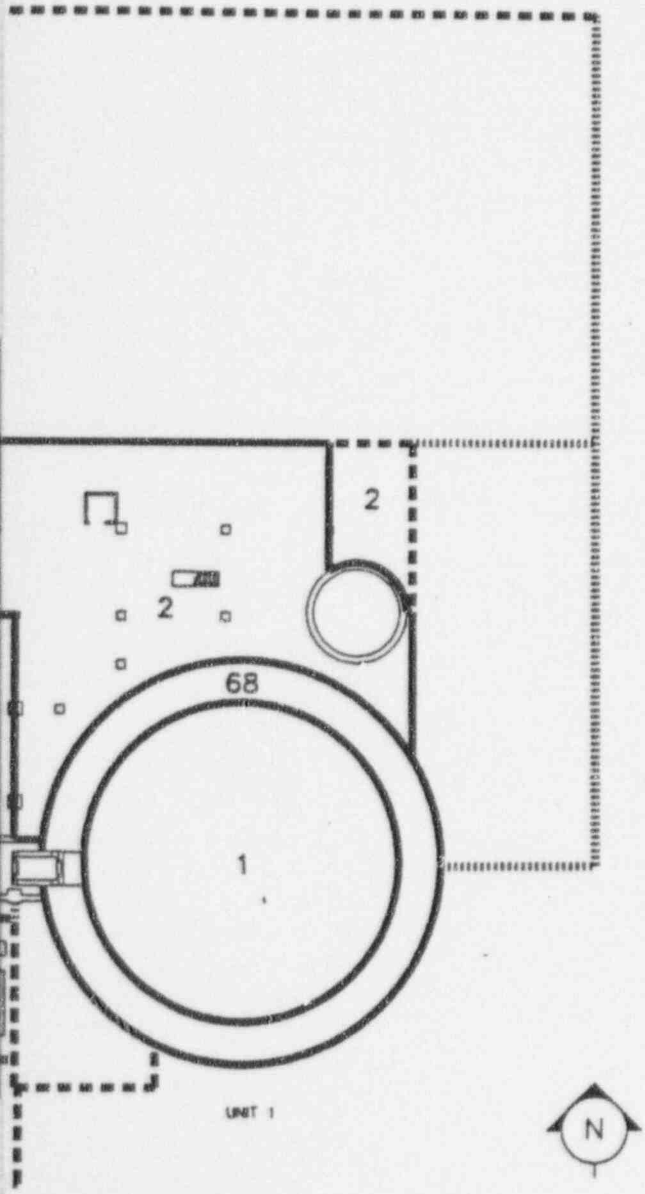
9612240185-03


7N
6N
8N
129N
130N
76
92
3
76
2
76
72
61A
71
62N
4N
UNIT 2

UPDATED P.I. OPNS

El. 755'



LEGEND

1- CONTAINMENT UNIT 1
2- VENT FAN ROOM UNIT 1
3- WATER CHILLER ROOM UNIT 1
4N- FUEL HANDLING AREA
6N- OLD ADMIN BLDG HVAC EQUIP. AREA
7N- OLD ADMIN BLDG OFFICE AREA
8N- TURB. DECK (UNITS 1 & 2)
61A- AUX. BLDG. HATCH AREA
62N- SPENT FUEL POOL AREA
68- CONTAINMENT ANNULUS UNIT 1
71- CONTAINMENT UNIT 2
72- CONTAINMENT ANNULUS UNIT 2
76- VENT . FAN ROOM UNIT 2
92- WATER CHILLER ROOM UNIT 2
129N- D5 RADIATOR EXHAUST (ROOF)
130N- D6 RADIATOR EXHAUST (ROOF)

XX - FIRE AREA

XXN - FIRE AREA CONTAINING NO SAFE SHUTDOWN EQUIPMENT.

- T.S.-3.14 BOUNDARIES (NUCLEAR SAFE SHUTDOWN) 10CFR50 APP.R (AREAS CONTAINING EQUIPMENT NECESSARY FOR SAFE SHUTDOWN DUE TO FIRE.

- GENERAL FIRE BOUNDARIES FOR BALANCE OF PLANT AND HIGH 3-HOUR BARRIERS.

- FIRE AREA BOUNDARY (FREE AIR SPACE).

Figure 1.1-1
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Individual Plant Examination
of External Events (IPEEE)

NSPLMI-96001

Appendix C
Revision 0

Other External Events

Table of Contents

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C.1 SUMMARY

C.1.1 Background

The assessment that is described in this appendix addresses the external events other than seismic and internal fires. These "other" external events include phenomena such as high winds, floods, transportation-related accidents and accidents at nearby facilities that could potentially pose a threat to the Prairie Island plant. This assessment is performed using the screening approach suggested in Generic Letter 88-20, Supplement 4 [1], and the accompanying guidance for implementation, NUREG-1407 [3].

C.1.2 Plant Familiarization

The Prairie Island Nuclear Generating Plant consists of two units, each employing a 2-loop pressurized water reactor. Northern States Power Company owns and operates the plant. Westinghouse Electric Corporation designed and supplied the nuclear steam supply system (NSSS), the initial reactor fuel, and the turbine-generator units. Pioneer Service and Engineering (now Fluor Power Services, Inc.) was the architect-engineer for the two units. Northern States Power Company was the constructor.

The plant was constructed, pursuant to Construction Permits CPPR-45 and CPPR-46, in Goodhue County, Minnesota. Construction started on June 26, 1968. Initial fuel loading was completed during Fall of 1973 for Unit 1 and Fall of 1974 for Unit 2. Following a period of testing, full commercial operation began on December 16, 1973 for Unit 1 under facility Operating License Number DPR-42, and on December 21, 1974 for Unit 2 under Facility Operating License Number DPR-60. The only significant new construction to occur since operation began was the recent addition of the D5/D6 Building, located adjacent to the Turbine and Auxiliary Buildings on the west side of the plant.

The reactor for each unit is capable of an ultimate power output of 1721.4 MWt, and all steam and power conversion equipment, including the turbine-generator, has the capability to generate a maximum calculated gross unit output of 583 MWe. All plant safety systems, including containment and engineered safeguards, were designed and originally evaluated for operation at the maximum power level of 1721.4 MWt.

Prairie Island was designed prior to the final issuance of the general design criteria for nuclear power plants (10CFR50, Appendix A) and the 1975 Standard Review Plan (NUREG-75/087) [6]. Instead, the Prairie Island design followed the proposed Atomic Energy Commission (AEC)

General Design Criteria published in the Federal Register on July 11, 1967 (32FR10213). The only exception to this was the recent addition of the D5/D6 Building which was designed as a Class I structure, but to more recent codes and standards. The review documented by this report considered the more recent criteria, and any significant differences from the General Design Criteria and Standard Review Plan are noted where applicable.

C.1.3 Overall Methodology

Generic Letter 88-20 Supplement 4 [1], along with NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities" [3], provide guidance for a screening technique that can be employed for assessing the potential impact of high winds and tornadoes, external floods, and transportation and nearby facility accidents on the safe operation of the plant. This screening approach was employed for Prairie Island.

Figure C.1 shows a flow chart of this screening approach. The approach consists of the following steps:

1. Reviewing plant-specific hazard data and licensing bases.
2. Identifying significant changes since the plant operating license was issued.
3. Determining if the plant and facilities design meets the 1975 Standard Review Plan (SRP) [6] criteria.

For the external events of high winds and tornadoes, external floods, and transportation and nearby facility accidents, a review of the SRP was conducted to determine if the criteria in the SRP are satisfied by the Prairie Island design bases. Because Prairie Island received its operating license prior to 1975, when the SRP was issued, it was necessary to review the Prairie Island Updated Safety Analysis Report (USAR) [14] and subsequently prepared analyses and calculations to make this assessment. If it was determined that the SRP requirements are satisfied, and a site walkdown confirmed that the current plant configuration is in agreement with the plant design bases, then the IPEEE screening criteria was considered satisfied.

If the SRP was not satisfied, then additional analyses may be necessary, such as a determination that hazard frequency is sufficiently low, performance of a bounding analysis, or the development of PRA models to evaluate the specific concerns.

Using the guidance and recommendations provided in Section 2 of NUREG-1407 [3], a number of the external events were determined not to require extensive evaluation due to specific rationale

(e.g., extremely low frequency, geographical considerations, etc.). These external events are as follows:

Lightning
Severe Temperature Transients (Extreme Heat and Extreme Cold)
Severe Storms (Including Duststorms and Sandstorms)
Extraterrestrial Activity
Volcanic Activity
Earth Movement (Including Avalanche and Landslide)
External Fires

Section 2.1 of the report addresses those external events not requiring extensive evaluation which are therefore eliminated from further consideration in the IPEEE. Sections 2.2, 2.3, and 2.4, respectively, provide the evaluation of the remaining external events:

High Winds and Tornadoes
External Flooding and Probable Maximum Precipitation
Transportation and Nearby Facility Accidents

Also, NUREG-1407 requests that licensees assess Generic Issue 103, "Design for Probable Maximum Precipitation (PMP)". Generic Letter 89-22, "Potential for Increased Roof Loads and Plant Area Flood Runoff Depth at Licensed Nuclear Power Plants Due to Recent Change in Probable Maximum Precipitation Criteria Developed by the National Weather Service" [2], refers to updated criteria which are to be reviewed by licensees to determine whether on-site flooding or roof ponding due to precipitation could cause a severe accident. Roof ponding is therefore addressed as part of the assessment for flooding, and is included in Section 2.3.2 of this report.

C.1.4 Summary of Major Findings

Based upon the evaluations presented in Section C.2 of this report, there is no "other" external event (fire and seismic are examined in separate appendices) that is a safety concern to the Prairie Island Plant. No vulnerabilities were identified, and the screening criteria contained in NUREG-1407 and Generic Letter 88-20, Supplement 4, are satisfied for all events. Because no vulnerabilities were found in this assessment, no changes to plant hardware or procedures are recommended.

Most of the external events considered could be readily eliminated from further consideration because they either do not apply to the Prairie Island site, or their impact has been determined to be insignificant. The remaining events (high winds and tornadoes, external flooding and probable maximum precipitation, and transportation and nearby facility accidents) were evaluated in greater detail.

Using the methodology presented in ASCE Paper No. 3269 [20], it was determined that the Prairie Island design of structures meets the acceptance criteria for high winds stipulated in SRP Section 3.3.1.

Tornadoes were evaluated for the three concerns of dynamic forces on structures resulting from the high winds generated, forces on structures from differential (negative) pressure from the tornado, and impact from missiles generated by the tornado. Using the guidance presented in Reg. Guide 1.76 [8] and ANSI/ANS 2.3-1983 [21], and employing additional deterministic and probabilistic analyses, it was determined that tornadoes do not impact the safe operation of the PINGP.

Flooding had been evaluated in the Prairie Island Probable Maximum Flood Study (Appendix F of the PINGP USAR) and it has been determined, using the most conservative assumptions for flood levels and precipitation, that the effects of flooding will not impact the safe operation of the plant.

Probable maximum precipitation was evaluated to determine effects on plant risk. Roof drainage was reviewed, including the potential to have ponding as a result of actual roof configuration. A walkdown was performed of the roofs for the Service Building, Auxiliary Building, Radwaste Building, Turbine Building, and D5/D6 Diesel Generator Building. Based on measurements from this walkdown and conservative calculations, it was determined that precipitation and potential ponding do not contribute to plant risk.

Transportation and nearby facility accidents were determined not to significantly contribute to plant risk. The plant is at least 2 statute miles from a federal airway, holding pattern, or approach pattern, and at least 5 statute miles from the edge of military training routes. It was also concluded that barge and ship traffic on the Mississippi River did not pose a threat to the safe operation of the plant either due to explosion or release of toxic materials. There are no gas pipelines near the plant site. Railroad accidents, on either of the two railroad lines that are in close proximity to the site, were determined not to pose a risk to plant safety. There is only one major highway within 5 statute miles of the plant. Shipment of hazardous material along this highway would be very infrequent. Local industry in the City of Red Wing, the nearest major industrial town, would pose no threat to the safe operation of the PINGP. There are no military facilities within 5 miles of the site.

Finally, a toxic chemical study [16] was performed which concluded that accidents from chemical releases from on-site storage would not impact the safe operation of the plant.

C.2 ASSESSMENT OF OTHER EXTERNAL EVENTS FOR PRAIRIE ISLAND

C.2.1 External Events Considered For Prairie Island

The following external events were reviewed for their impact on the design bases of the plant and were determined to have no significant impact on core damage frequency, for the specific reasons noted for each event. They were therefore excluded from further analysis.

Lightning: At Prairie Island, lightning protection exists for the Containment Buildings, Auxiliary Building, Turbine Building, Screenhouse, Cooling Tower Substation, and Plant Substation. The lightning protection system satisfies NFPA Standard 78-1975 requirements [30].

As stated in NUREG-1407, the primary impact of lightning on nuclear power plants is the loss of offsite power (LOOP).

A review of plant operating history was performed which identified the following lightning-related events at Prairie Island:

In September, 1978, an apparent lightning strike on the 161 kV transmission line ultimately resulted in the loss of two sources of offsite power, leaving only one source of offsite power in operation [27]. This event occurred at a time when one of the two Diesel Cooling Water Pumps was out of service for maintenance. However, a second offsite power source was restored before an orderly plant shutdown needed to be accomplished; therefore, neither plant unit was taken to cold shutdown. A transformer was damaged during the event and was subsequently replaced.

Due to an apparent lightning strike on the 345 kV transmission line in July, 1980, the Unit 2 main generator was separated from the grid and one offsite power source was lost [28]. This situation resulted in a subsequent trip of the reactor and the reactor coolant pumps. Natural circulation was established for core cooling for Unit 2 (at the time of the event Unit 1 was in cold shutdown). Shortly thereafter, another transformer was locked out, leaving only one source of offsite power. The diesel generators successfully started, supplying power to the safeguard buses. Approximately one hour later both offsite sources that were previously lost were restored.

In September, 1982, an apparent lightning strike on the 345 kV transmission line caused the Unit 2 Main Generator output breakers to open, ultimately causing a Unit 2 trip [29]. The unit was subsequently restarted with no major problems encountered during recovery.

No damage to safety related equipment occurred as a result of these three events, and in the case of the plant trips, no system required for safe reactor shutdown failed.

The loss of offsite power is included as part of the internal events IPE, and examination of the vulnerabilities due to this aspect of lightning is therefore already included in the IPE process. Therefore no further analysis of this event is necessary.

Severe Temperature Transients (Extreme Heat and Extreme Cold): As stated in NUREG-1407, the effects of severe temperature are usually limited to reducing the capacity of the ultimate heat sink (UHS) and increasing the loss of offsite power (LOOP) frequency. The climatology of the Prairie Island site locale is such that extreme cold would potentially have more significant effects on plant operation than would extreme heat. Plant piping and equipment located outside of plant buildings are protected by heat tracing to prevent adverse effects from severe cold. Furthermore, the capacity reduction of the UHS due to extreme cold would be a slow process that would allow plant operators sufficient time to take proper actions, such as reducing plant power output level or achieving safe shutdown. Also, to preclude the possibility of a reduction in UHS capability, PINGP Operating procedure C25, "Circulating Water System" [24], places the plant deicing system in operation to prevent the traveling screens from icing up during winter months. The deicing system is placed in service when Mississippi River water temperatures drop to 40 degrees F, and the system remains in operation until the river temperatures rise above 40 degrees.

Regarding the effects of a Loss of Offsite Power, the LOOP is included as part of the internal events IPE process.

Based on the above considerations, it is concluded that no further analysis for severe temperature transients is necessary.

Severe Storms (Includes Ice, Hail, Snowstorms, Duststorms, and Sandstorms): The potential impacts of these events on Prairie Island is the increased potential for a loss of offsite power (LOOP) event, effect on control room habitability, and effect on the UHS. LOOP is included as part of the internal events IPE. It is extremely unlikely that a duststorm or sandstorm would occur at the Prairie Island site, let alone have an adverse effect on the habitability of the control room. However, if this did occur, the operators would have sufficient time to don proper breathing apparatus. Any capacity reduction of the UHS due to the impact of these storms would be a slow process which would allow sufficient time for appropriate operator actions (such as reducing plant power output level or achieving safe shutdown). Winds and precipitation resulting from storms are specifically addressed in Sections 2.2 and 2.3. Therefore, no further analysis of these events is necessary.

External Fires: External fires are fires that take place outside the site boundary and involve forest, crops, grass or other vegetation. The chance of the fire traveling onto areas of the site containing critical plant equipment is minimal due to the fact that these areas are cleared, having an insignificant number of trees and major foliage. The only potential impacts from an external fire would be LOOP, and smoke and gases entering the control room environment. If a LOOP should occur as a result of an external fire, its impact on plant accident response would be modeled by the PINGP IPE. Smoke and gases degrading control room habitability is deemed extremely unlikely, since insignificant amounts of gases would reach the control room atmosphere. However, if such an event were to occur, plant operators would have sufficient time to take appropriate control room action, such as donning the protective air masks available within the control room if the concentration of smoke begins to increase. Therefore it is concluded that external fires pose no hazard to the PINGP, and they are eliminated from further analysis.

Extraterrestrial Activity: Extraterrestrial activity is considered to be natural satellites such as meteors, or artificial satellites that enter the earth's atmosphere from space. As stated in Supplement 2 to NUREG/CR-5042 [5], the probability of such extraterrestrial activity is very low, and therefore this hazard can be dismissed on the basis of the infrequency of the initiating event.

Volcanic Activity: No sources of volcanic activity exist near the Prairie Island site. Therefore, no volcanic activity analysis is necessary.

Earth Movement (i.e., Avalanches, Landslides): Avalanches are not applicable to any plant in the United States. As discussed in NUREG/CR-5042 [4], the NRC has also deemed that landslides and other large earth movements (other than those caused by seismic events) would have an insignificant impact on all plants. The Prairie Island site is on level ground with slightly rolling hills, having an elevation variance of approximately 35 feet. Therefore it is concluded that earth movements would pose no threat to Prairie Island, and no further analysis of this event is required.

C.2.2 High Winds and Tornadoes

In this section, the effects of high winds and tornadoes are evaluated against the plant design bases. The results of this evaluation are presented below.

C.2.2.1 High Winds

The NRC acceptance criteria for high winds is stated in Standard Review Plan Sections 3.3.1 (Wind Loadings). SRP Section 3.3.1 states that ". . . the procedures delineated in either the American Society of Civil Engineers (ASCE) Paper No. 3269, 'Wind Forces on Structures' . . . or in ANSI

A58.1-1972, 'Building Code Requirements for Minimum Design Loads in Buildings and Other Structures' . . . are acceptable" for addressing wind velocity and effective pressure applied to exposed surfaces of structures.

PINGP USAR Section 12.2.1.3.1, Environmental Loads, states that the design wind speed for Prairie Island is 100 mph. Wind pressure, shape factors, gust factors, and variation of winds with height have all been determined in accordance with the methodology presented in ASCE 3269.

Based on the fact that the ASCE 3269 methodology was employed for wind design for plant structures, the Prairie Island design meets the acceptance criteria for high winds stipulated in SRP Section 3.3.1.

Additionally, as is demonstrated in Section 2.2.2 of this report, the effect of high winds is bounded by the maximum winds produced by the design basis tornado.

Therefore it is concluded that high winds contribute no significant safety risk at the PINGP.

C.2.2.2 Tornadoes

The potential hazard from tornadoes arises from three concerns:

- dynamic forces on structures resulting from the high winds;
- forces on structures resulting from differential (negative) pressure from the tornado;
- impact forces from missiles generated from the tornado.

The NRC acceptance criteria for tornadoes is given in Standard Review Plan Sections 3.3.2 (Tornado Loadings), 3.5.1.4 (Missiles Generated by Natural Phenomena), 3.5.2 (Structures, Systems, and Components to be Protected from Externally Generated Missiles), and 3.5.3 (Barrier Design Procedures). Supplementary guidance is provided in Regulatory Guide 1.76, "Design Basis Tornado for Nuclear Power Plants" [8] and Regulatory Guide 1.117, "Tornado Design Classification" [13].

According to Reg. Guide 1.76, the PINGP site is located in Tornado Region I. The characteristics of a design basis tornado in that region are as follows:

Maximum Wind Speed (mph):	360
Rotational Speed (mph):	290
Maximum Translational Speed (mph):	70
Pressure Drop (psi):	3.0
Rate of Pressure Drop (psi/sec):	2.0

Section 12.2.1.3.2 of the PINGP USAR, Tornado Loads, states that the tornado loadings used in the design of PINGP Class I structures (except for the D5/D6 Diesel Generator Building, which is discussed below) are as follows:

- A differential pressure equal to 3 psi. This pressure is assumed to build up from normal atmospheric pressure in 3 seconds.

- A lateral force caused by a funnel of wind having a peripheral tangential velocity of 300 mph and a forward progression of 60 mph.

- The design tornado-driven missile was assumed to be equivalent to an airborne 4" x 12" x 12' plank traveling end-on at 300 mph, or a 4000-pound automobile flying through the air at 50 mph and at not more than 25 feet above ground level.

Section 12.2.1.3.2 of the USAR also states that the tornado loadings used in the design of the D5/D6 Diesel Generator Building, which houses the PINGP Unit 2 Diesel Generators D5 and D6, are as follows:

- A lateral force caused by a funnel of wind having a rotational speed of 290 mph and maximum translation speed of 70 mph.

- A pressure drop of 3.0 psi, with the rate of pressure drop being 2.0 psi/sec.

- The design tornado generated missiles as shown in PINGP USAR Table 12.2-43.

The design bases of the PINGP Class I structures (excluding the D5/D6 Diesel Generator Building) is slightly less severe than the criteria stipulated in SRP 3.3.2 with regard to maximum wind speed (300 vs. 360 mph) and rate of pressure drop (1.0 vs. 2.0 psi/sec). However, Figure 3.2-1 of ANSI/ANS-2.3-1983, "Standard for Estimating Tornado and Extreme Wind Characteristics at Nuclear Power Sites" [21], indicates that the PINGP is located in a geographical area where the probability of experiencing tornado wind speeds of 320 mph or greater is 10^{-7} per year (the ANSI figure is reproduced in this report as Figure C.2). Figure 3.2-2 of that ANSI standard (reproduced in this report as Figure C.3) indicates that the probability of the PINGP experiencing tornado wind speeds of 260 mph or greater is 10^{-6} per year. Therefore the probability of the PINGP experiencing tornado wind speeds in excess of the design bases value of 300 mph is between 10^{-6} and 10^{-7} per year. Based on this low probability of occurrence, it is concluded that the PINGP design bases for tornado wind speed is acceptable.

According to USAR Section 12.2.1.3.2, the design bases for the D5/D6 Diesel Generator Building with regard to tornado wind loadings and tornado generated missiles are: a lateral force caused by a funnel of wind having a rotational speed of 290 mph and a maximum translation speed of 70 mph; a pressure drop of 3.0 psi with a rate of pressure drop of 2.0 psi/sec; and the design tornado-generated missiles as shown in USAR Table 12.2-43. Table 12.2-43 is repeated below:

Table C.1
D5/D6 Building
Tornado Generated Missiles

Missiles	Dimension (meters)	Mass (kilograms)	Velocity(meters/sec)*
Wood Plank	0.092 x 0.289 x 3.66	52	83
6 inch Sch 40 Pipe	0.168 Diameter x 4.58	130	52
1 inch Steel Rod	0.0254 Diameter x 0.915	4	51
Utility Pole	0.343 Diameter x 10.68	510	55
12 inch Sch 40 Pipe	0.32 Diameter x 4.58	340	47
Automobile	5 x 2 x 1.3	1810	59

* Velocities are horizontal velocities. For vertical velocities, 70 percent of the horizontal velocities shall be used.

These criteria for wind loadings and tornado-generated missiles meet the design requirements specified in Reg. Guide 1.76, SRP 3.3.2, and SRP 3.5.1.4. Therefore the design of the D5/D6 Diesel Generator Building is acceptable.

Regarding the PINGP Unit 1 Diesel Generators D1 and D2, the design of the D1 Diesel Generator room door, as well as portions of the D1 and D2 combustion exhaust piping and HVAC supply ducting, did not explicitly consider protection from tornadoes. (Portions of the exhaust piping and the HVAC ducting are located in non-Class I structures and are not tornado-protected; the D1 Diesel Generator room door is not Class I and is not designed to act as a missile barrier.) A probabilistic analysis was performed to determine the risk resulting from the potential failure of D1 and D2 Diesel Generators from a tornado [17]. The calculation evaluated the effects of tornado dynamic forces, pressure drop and tornado-generated missiles, as well as the plant response in the event of the failure of both the D1 and D2 Diesel Generators.

The calculation identified eleven possible combinations for the failure of Diesel Generators D1 and D2 and estimated a frequency of occurrence for each failure combination. The eleven combinations and their calculated frequencies of occurrence are as follows:

Table C.2
Combinations of D1/D2
Failures and Frequencies

Combination	Frequency (yr^{-1})
Both combustion exhaust pipes struck	9.2E-11
D2 exhaust pipe and D1 door struck	5.2E-11
D1 exhaust pipe struck and D2 fails to start/load	5.0E-9
D2 exhaust pipe struck and D1 fails to start/load	1.1E-8
HVAC duct and D1 door struck	3.6E-11
HVAC duct and D1 exhaust pipe struck	6.4E-11
HVAC duct and D2 exhaust pipe struck	1.4E-10
HVAC duct struck and D1 fails to start/load	7.6E-9
HVAC duct struck and D2 fails to start/load	7.6E-9
HVAC duct struck disabling both EDGs	<1E-7*
D1 door struck and D2 fails to start/load	2.9E-9

*Note: The probability of the HVAC duct being struck and disabling both EDGs is not quantified but is significantly less than 1E-7 since the probability of crushing the duct (resulting in inadequate ventilation flow for one EDG) is necessarily much less than the overall missile strike probability for the duct.

Based on these results, the calculation concluded that the overall risk from the loss of both the D1 and the D2 Diesel Generators due to tornado missile impact on either the combustion exhaust piping, the HVAC supply ducting, or the D1 Diesel Generator room door, is less than approximately 10^{-7} per year, and thereby meets the acceptance criteria provided in Standard Review Plan Section 3.5.1.5, which requires that the probability of site proximity missiles impacting the plant and causing radiological consequences greater than Part 100 guidelines must be less than approximately 10^{-7} per year.

The calculation also evaluated the effects due to tornado pressure drop on the D1 and D2 Diesel Generator combustion exhaust piping, HVAC supply ducting and the D1 Diesel Generator room door. For the combustion exhaust piping the calculation concluded that, based on the 3/8" wall

thickness of the pipe, there would be no effect on the piping integrity as a result of the tornado pressure drop. For the HVAC supply ducting, the calculation concluded that even if the ducting were to fail due to excessive pressure forces, it was not considered credible that the ducting would crush to the extent that its flow area would be significantly restricted. This conclusion is further supported by the existence of vertical supports in the ducting which would resist a collapse of the ducting. For the D1 Diesel Generator room door, the calculation concluded that no hazard to the D1 Diesel Generator is expected due to failure of the room door, since any failure of the door due to tornado pressure drop would cause the door to be forced away from the D1 Diesel Generator room and into the service building area.

The overall conclusion of the calculation was, therefore, that the existing configuration of the D1 and D2 Diesel Generator combustion exhaust piping, HVAC supply ducting, and the D1 Diesel Generator room door, relative to tornado protection, is acceptable. This conclusion is based on the demonstration that these components are either adequately designed to withstand tornado effects or that the probability of a loss of D1 and D2 Diesel Generators due to failure of these components during a tornado is sufficiently low to require no further analysis. Furthermore, the calculation states that, even if D1 and D2 Diesel Generators were unavailable, procedures exist for supplying AC power to Unit 1 from the Unit 2 D5 and D6 Diesel Generators within 10 minutes of the blackout occurring.

Based on the existing design bases of PINGP structures relative to the effects of high winds and tornadoes, it is concluded that tornado events can be eliminated from consideration as being a significant contributor to plant risk.

C.2.3 External Flooding and Probable Maximum Precipitation

This section of the report consists of assessments for both the external flooding event and the probable maximum precipitation event. The assessment for external flooding is presented in Section 2.3.1. The assessment for probable maximum precipitation, including an assessment for roof ponding, is presented in Section 2.3.2.

C.2.3.1 External Flooding

The NRC acceptance criteria for external flooding is stated in Standard Review Plan Sections 2.4.2 (Floods), 2.4.3 (Probable Maximum Flood on Streams and Rivers), 2.4.10 (Flooding Protection Requirements), and 3.4.1 (Flood Protection). Supplementary guidance is provided in Regulatory Guide 1.59, "Design Basis Floods for Nuclear Power Plants" [7] and Regulatory Guide 1.102, "Flood Protection for Nuclear Power Plants" [12].

External flooding at the PINGP site would be as a result of a rise in the water level of the Mississippi, the Minnesota, and the St. Croix Rivers, as well as numerous tributaries. According to estimates by US Army Corps of Engineers, a flood in the vicinity of the site would have a 1000-year occurrence of approximately 693.5 mean sea level (MSL) (1929 Adjustment).

Prairie Island has performed an analysis for determining the Probable Maximum Flood (PMF). This analysis is presented in PINGP USAR Appendix F [15]. In this report, probable maximum flood was defined as the hypothetical flood that would result if all the factors that contribute to the generation of the flood (e.g., precipitation rates, soil infiltration and retention rates, spring and summer storm levels, snow fall and snow melt rates, temperature sequences, etc.) were to reach their most critical values concurrently. This probable maximum flood is derived from hydrometeorological and hydrological studies and is independent of historical flood frequencies.

The study states that the probable maximum discharge at the Prairie Island site has been determined to be 910,300 cubic feet per second (cfs), with a corresponding peak stage of 703.6 feet MSL (1929 adjustment). This is equivalent to 704.1 feet MSL using the 1912 datum mean sea level (as in the USAR, this evaluation will use the 1929 datum to ensure consistency). The study has determined that this probable maximum flood condition would reach its maximum level about 12 days after the beginning of high temperatures and would remain above a flood stage of 681.0 feet MSL (1929 adjustment) for about 30 days. The maximum one percent wave height, consistent with the highest significant wave, is estimated to be less than 3.1 feet from trough to crest. Therefore if the conservative assumption is made that run-up equals the approaching wave height, then the maximum water level would be 706.7 feet MSL (1929 adjustment). According to PINGP USAR Section 2.4.3.5, Floods, ". . . the plant is designed such that all areas critical to nuclear safety are protected against the effects of the probable maximum flood and associated maximum wave run-up."

The Reactor Buildings, the Auxiliary and Fuel Handling Building, the Turbine Building, and the Class I portion of the Screenhouse Structure are protected against the effects of the probable maximum flood and associated maximum wave run-up to an elevation of 706.7 feet MSL (1929 adjustment). All openings from the plant exterior into these buildings below the maximum flood level are protected by flood barriers (stop logs). The base slabs of these structures have been designed to resist the full hydrostatic head of the PMF. Additionally, these structures were checked regarding the buoyant force due to the PMF and were found to have an adequate design to prevent uplift from such buoyant force [15].

Long-range weather forecasts and flood advisories are available through the National Weather Service and are routinely monitored by NSP. They would afford the PINGP ample warning of an impending flood. Abnormal Operating Procedure AB-4, "Flood" [23], specifies the actions to be performed if flood levels reach 683 feet MSL (1929 adjustment).

The PINGP will sustain regular operation to a flood stage of 692 feet MSL (1929 adjustment). When the flood stage exceeds 692 feet MSL, both units would be taken to hot standby, and the

main generator disconnect links would be removed from the generator leads of both units per Technical Specification 6.5.A.6. Offsite power would then be available through any of the offsite transformers and 1R and 2R. Control circuitry for the respective source breaker in the plant substation would be defeated, and fault protection would be provided at the source end of all offsite transmission lines. In this way, two different paths of offsite power could be provided up to a flood level of 698 feet MSL.

In the event of loss of offsite power, the Unit 1 design minimum supply of diesel fuel oil is 70,000 gallons, which is sufficient to operate one diesel generator and one diesel cooling water pump for more than 14 days. The Unit 2 design minimum supply of diesel fuel oil is 75,000 gallons, which is sufficient to operate one diesel generator set for 14 days.

Based on the existing design bases of the PINGP, it is concluded that the effects due to external flooding do not impact the safe operation of the PINGP.

C.2.3.2 Probable Maximum Precipitation

Generic Letter 89-22, "Potential for Increased Roof Loads and Plant Area Flood Runoff Depth at Licensed Nuclear Power Plants due to Recent Change in Probable Maximum Precipitation Criteria Developed by the National Weather Service" [2], informed licensees that more recent probable maximum precipitation (PMP) criteria had been published by the National Oceanic and Atmospheric Administration (NOAA)/National Weather Service (NWS). These criteria are contained in NOAA/NWS Hydrometeorological Reports (HMR) No. 49 (1977), No. 51 (1978), No. 52 (1982), No. 53 (1980), and No. 55 (1984). The criteria contained in these documents call for higher rainfall intensities over shorter time intervals and over smaller areas than have been previously considered. This could potentially lead to higher site flood levels and greater roof ponding loads than have previously been considered. For the IPEEE, licensees should review this new precipitation criteria against their existing design bases in terms of revised flood levels and higher roof ponding values.

Regarding increases in the magnitude of flood levels, Appendix F of the PINGP USAR documents a study to determine the probable maximum flood (PMF). The study considered, among other parameters, the heaviest possible contribution to the flood by precipitation. The study includes the following definition of "probable maximum flood":

> The probable maximum flood is derived from hydrometeorological studies and is independent of historical flood frequencies. It is the estimate of the boundary between possible floods and impossible floods. Therefore, it would have a return period approaching infinity and a probability of occurrence, in any particular year, approaching zero.

Therefore it is judged that the flood levels determined in the USAR Appendix F analysis would bound the levels calculated by the criteria given in Generic Letter 89-22.

Regarding roof ponding (accumulation of water on the structure roof resulting from precipitation), a review of the existing configuration of the Class I structures at the PINGP was made to determine if roof ponding would adversely impact the design bases of the structure. The conservative assumption was made that all the drains would be plugged. A certain amount of water, therefore, would remain on the structure roof, an amount that would depend upon the actual roof configuration. This amount of water remaining on the roof would be assessed to determine if it exceeds the design loading of the roof and could pose a hazard.

To aid in this determination, a walkdown of the roofs was performed for the Service Building, Auxiliary Building, Radwaste Building, Turbine Building, and D5/D6 Diesel Generator Building. The purpose of the walkdown was to determine the amount of water that could physically accumulate on the roof, assuming that the roof drains were inoperable. The roofs were examined for configuration, slope, and size of roof rim or parapet.

The results of this walkdown are presented below.

For the Service Building, the roof was verified to be essentially flat, sloping toward the existing roof drains. Metal flashing runs along the north, east, and south edges of the roof, creating a rim conservatively measured as 5" higher than the surface of the roof. In the event of precipitation, if the roof drains were plugged, a pond of water would develop, covering the entire surface of the roof. The water would accumulate until the level of the top of the rim was reached (approximately 5" high), and then the water would start spilling over the rim and off the roof.

As stated in PINGP USAR Section 12.2.1.3.1, Environmental Loads, "snow load of 50 lbs per sq ft of horizontal projected area is used in the design of structures and components exposed to snow". This criterion is from applicable codes and standards, including the Uniform Building Code which accounts for snow loading in the safe design of structures. Using a weight of water of 62.4 pounds per cubic foot and assuming a conservative height of water of 5", the weight resulting from the water ponding would be 26 pounds per square foot. Therefore the maximum amount of water that could physically accumulate on the roof of the Service Building would not approach the design load limit of 50 pounds per square foot.

For the Auxiliary Building, the roof was verified to be essentially flat, sloping toward the existing roof drains. Metal flashing runs along the east and west edges of the roof, creating a rim conservatively measured as 5" higher than the surface of the roof. In the event of precipitation, if the roof drains were plugged, a pond of water would develop covering the entire surface of the roof. The water would accumulate until the level of the top of the rim was reached (approximately 5" high), and then the water would start spilling over the rim and off the roof. The maximum weight load on the Auxiliary Building roof due to water ponding, therefore, is 26 pounds per square foot, considerably less than the design value of 50 pounds per square foot.

For the Radwaste Building, the roof was verified to be essentially flat, sloping toward the existing roof drains. Metal flashing runs along all four edges of the roof, creating a rim conservatively measured as 7" higher than the surface of the roof. The maximum weight load on the Radwaste Building roof due to water ponding is, therefore, 36.4 pounds per square foot, considerably less than the design value of 50 pounds per square foot.

For the Turbine Building, the roof was verified to be essentially flat, sloping toward the existing roof drains. Metal flashing runs along all four edges of the roof, creating a rim conservatively measured as 7" higher than the surface of the roof. The maximum weight load on the Turbine Building roof due to water ponding is, therefore, 36.4 pounds per square foot, considerably less than the design value of 50 pounds per square foot.

For the D5/D6 Diesel Generator Building, there are two roofs involved: the main roof of the D5/D6 Diesel Generator Building and the roof to the ventilation compartment on top of the main roof. The main roof of the D5/D6 Diesel Generator Building was verified to be essentially flat, sloping toward the existing roof drains. Metal flashing runs along the north, west, and south sides of the roof, creating a rim conservatively measured as 5" higher than the surface of the roof. The maximum weight load on the D5/D6 Diesel Generator main roof due to water ponding is, therefore, 26 pounds per square foot, considerably less than the design value of 50 pounds per square foot.

The smaller roof of the ventilation compartment atop the D5/D6 Diesel Generator Building main roof was verified to be sloped, with no existing rim. Therefore, all the precipitation landing on the roof would flow off.

Therefore, for the roofs of the Service Building, Auxiliary Building, Radwaste Building, Turbine Building, and D5/D6 Diesel Generator Building, it is concluded that water ponding does not pose a hazard by impacting the design bases of the structures, and therefore does not contribute to plant risk.

C.2.4 Transportation and Nearby Facility Accidents

The NRC acceptance criteria for transportation and nearby facility accidents is stated in Standard Review Plan Sections 2.2.1-2.2.2 (Locations and Routes, Descriptions), 2.2.3 (Evaluation of Potential Accidents), and 3.5.1.6 (Aircraft Hazards). Supplementary guidance is provided in Regulatory Guide 1.78, "Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release" [9], Regulatory Guide 1.91, "Evaluations of Explosions Postulated to Occur on Transportation Routes Near Nuclear Power Plants" [10], and Regulatory Guide 1.95, "Protection of Nuclear Power Plant Control Room Operators Against an Accidental Chlorine Release" [11].

In accordance with the guidance presented in NUREG/CR-5042, hazards associated with transportation accidents include:

Aviation accidents (Commercial, General, and Military)
Marine accidents (Ship and Barge)
Pipeline accidents (Gas and Oil)
Railroad accidents
Truck accidents

In accordance with the guidance presented in Supplement 2 of NUREG/CR-5042, hazards associated with nearby facility accidents include:

Accidents in nearby industrial facilities
Accidents in nearby military facilities
Hazardous material releases from on-site storage

As defined by NUREG-1407 (Chapter 5), the term "nearby" refers to being within 5 miles of the site.
Each of these individual accidents are addressed in the sections below.

C.2.4.1 Aviation Accidents

To assess the potential for aviation accidents and their consequences to the plant, the initial step is to determine whether conditions exist that make this a credible scenario. These conditions include the proximity of the plant to commercial and military airfields, the number of flights taking off and landing at these airfields, and the proximity of the plant to the path of approaches, routes and holding patterns of commercial and military aircraft.

In accordance with the acceptance criteria given in SRP 3.5.1.6 [6], the probability of an aircraft accident resulting in radiological consequences greater than 10 CFR Part 100 guidelines is considered to be less than 10E-7, provided that:

1. The plant-to-airport distance D is between 5 and 10 statute miles, and the projected annual number of operations is less than 500 D^2, or the plant-to-airport distance D is greater than 10 statute miles, and the projected annual number of operations is less than 1000 D^2;

2. The plant is at least 5 statute miles from the edge of military training routes, including low-level training routes, except for those associated with a usage greater than 1000 flights per year, or where activities (such as practice bombing) may create an unusual stress situation;

3. The plant is at least 2 statute miles beyond the nearest edge of a federal airway, holding pattern, or approach pattern.

There are two airports that are relatively close to the PINGP: the Minneapolis/St. Paul International Airport and the Red Wing Airport. Each of these two airports is evaluated below, with regard to the three acceptance criteria of the SRP.

As stated in PINGP USAR Section 2.2.1, "Location", the plant is located at 44° 37.3' north latitude and 92° 37.9' west longitude. The Minneapolis/St. Paul International Airport is located at 44° 53' north latitude and 93° 13' west longitude [26]. Therefore the distance between the plant and the airport is approximately 30 statute miles. Substituting a value of 30 for D in the appropriate equation for maximum acceptable number of projected annual operations gives:

Maximum Acceptable Number of Operations = $1000\ D^2 = 900{,}000$.

Since the projected annual number of airport operations from August 1996 to July 1997 is 494,197 [26], the first criterion is satisfied.

There are no military training routes or low-level training routes within five statute miles of the plant [26]. Therefore the second criterion is satisfied.

As stated in Reference 26: "The only airway in the vicinity of the Prairie Island plant is V-2/97, the 125 radial of the Gopher VOR, which passes approximately three miles to the northeast of the plant's location. The extended final approach course for Runways 29R and 29L passes approximately two and three miles south of the plant. However, the final approach normally extends only twenty to twenty-five miles out. The plant is located nearly 30 miles southeast of the airport. On limited occasions the final may extend out to 30 miles. It would occur during a heavy arrival rush and would last for only a brief period. Only about four aircraft would transit the area during each rush and we have approximately six of these periods of heavy traffic daily. Annually, 49% of the traffic land on Runways 29L and R. "Therefore it is concluded that the third criterion is satisfied for the Minneapolis/St. Paul International Airport.

As stated in Reference 26: "The Red Wing Airport is located approximately six miles east of the plant at 44° 35.41' north latitude and 92° 29.17' west longitude. The airport traffic pattern extends 2.5 miles southwest of the airport. The airport primarily services small general aviation aircraft and had 3294 instrument operations in the past year. "The distinction made regarding "instrument" operations at Red Wing refers to those operations known by the FAA. Operations involving "visual" landings and take-offs are not tracked by the FAA at small airfields (such as Red Wing) for which there is no tower. Therefore, the total number of operations is not known. However, it should be noted that most operations at these small airfields involve small planes, and usually involve recreational flying during daylight hours under good weather conditions.

The distance between the plant and the Red Wing airport is approximately six statute miles. Substituting a value of six for D in the appropriate equation for maximum acceptable number of projected annual operations gives:

Maximum Acceptable Number of Operations = $500 D^2 = 18{,}000$.

Since the Red Wing Airport had only 3294 instrument operations in the past year, there would have to be on the order of 15,000 visual operations to exceed the first criterion. This would correspond to over 40 additional flights per day if spread evenly over the year. Red Wing does not approach having this level of activity. Therefore, it is concluded that the first criterion is satisfied.

As stated above, there are no military training routes or low-level training routes within five statute miles of the plant. Therefore the second criterion is satisfied.

The airport traffic pattern extends 2.5 miles southwest of the airport. Since the airport is approximately six miles east of the plant, it is concluded that the third criterion is satisfied.

Based on satisfying the three criteria for each of the nearby airfields, it can be concluded that there is no hazard to the safe operation of Prairie Island. This evaluation has shown that the opportunity for having such an accident is highly remote, making further analysis of accident consequences unnecessary.

C.2.4.2 Marine Accidents

Marine accidents pose a hazard due to the possible release of hazardous material towards the plant and/or the possibility of explosion and fire with resulting physical damage to the plant due to blast, debris and fire. There is also the possibility of physical damage to the cooling water intake and outlet structures due to collisions by the ship or barge.

As stated in PINGP USAR Section 2.9.1, "Effects of Oil Spillage", and 2.9.2, "Postulated Explosion of Munitions Barge", the Prairie Island plant is fully protected from the possible effects of oil spillage on the Mississippi River by a permanent barrier wall or skimmer that has submerged flow openings. The safety related emergency intake is submerged well below the normal river levels. Therefore a spill will not affect the emergency intake system. In addition, the suction intakes for the Circulating Water System, the Cooling Water System, and the plant fire pumps are submerged in bays within the Screenhouse structure.

Regarding the possibility of explosion and fire, the explosion of a munitions barge on the Mississippi River has been postulated. This hazard is based on a hypothetical jumbo barge (195 feet long, 35 feet wide, and having 8-1/2 feet of draft) fully laden with 1400 tons of TNT, with the cargo exploding in mid-channel 2600 feet directly east of the plant. The resulting blast effect of 2.25 psi and the transient wind velocity of 78 mph was conservatively obtained by assuming the

entire detonation occurs at the surface of the water even though most of the explosives would be located below the waterline.

The control room is designed for the postulated blast without injury to its occupants. The entire room is enclosed with a two-foot thickness of concrete, except for the north wall which is 18 inches thick, and is surrounded by other structures. Conservative application of the linear and rotational components of tornado velocities for those areas of the structure that would be exposed to the blast has effectively resulted in design for a 2.25 psi internal loading, plus allowance for missiles and earthquakes. The USAR states in Section 2.9.2 that some damage from such a blast may be expected to occur to light external structures. However, the USAR also states that this damage would be consistent with the intent of the design for these structures with regard to tornado forces.

With regard to the effects of toxic chemicals, according to the PINGP Control Room Habitability Toxic Chemical Study [16], data was obtained from the U.S. Army Corps of Engineers for barge traffic along the Mississippi River. From this data it was determined that the only substances that were shipped in 1990 in excess of RG 1.78 criteria (i.e., shipments of 50 times per year) were chemical fertilizers. These fertilizer shipments had an average weight of 2000 tons. Although chemical fertilizers can be used in creating a potent explosive, this would require additives that are not normally included in such shipments. Introducing these additives to the chemical fertilizer shipment would constitute an act of attempted sabotage which is outside the scope of the IPEEE investigation. The conclusion of the study was that since chemical fertilizers represented the only hazardous material shipped, toxic chemical shipment by barge does not pose a hazard to the PINGP.

Additionally, an analysis was performed to determine the vulnerability of the cooling water intakes to a hypothetical barge collision. As stated in PINGP USAR Section 2.9.3, "Vulnerability of Cooling Water Intakes to Barge Collision", the total loss of plant cooling capability is not credible since, in order to disable all supplies of cooling water, an accident would have to result in concurrently blocking the intake screenhouse structure screens and totally damaging or blocking the emergency intake structure. Emergency bypass gates are provided in the intake screenhouse to prevent the possibility of eliminating all supplies of cooling water. The emergency intake structure is designed and located to preclude total blocking by the postulated accident.

Based on the above analyses, it is concluded that marine accidents could not impact the safe operation of the PINGP.

C.2.4.3 Pipeline Accidents

Pipeline accidents pose a hazard due to the release of hazardous material and/or the possibility of explosion. As stated in PINGP USAR Section 2.2.4.4, "Nearby Industrial, Transportation, and

Military Facilities", no large natural gas pipelines pass close to the plant site. Therefore no further assessment of pipeline accidents need be performed.

C.2.4.4 Railroad Accidents

Railroad accidents pose a hazard to a nuclear power plant due to the possible release of hazardous material and/or the possibility of explosion and fire. Physical damage to the plant due to actual collision with plant structures is considered minimal due to the distance between main rail lines and plant structures.

As stated in PINGP USAR Section 2.2.4.4, "Nearby Industrial, Transportation, and Military Facilities", there are two railroads within 5 miles of the site:

- The Soo Line Railroad, which runs across the southwest portion of the PINGP site and is within approximately 0.2 miles of the site;
- The Burlington Northern Railroad, which runs on the opposite side of the Mississippi River in Wisconsin and is within approximately 2 miles of the site.

The guidance presented in Regulatory Guide 1.91 [10] was employed to evaluate the effects of a railroad car explosion. Regulatory Guide 1.91 states that the maximum probable explosive cargo in a single railroad box car can be assumed to be 132,000 pounds (of TNT equivalent). The regulatory guide also provides the following formula for determining the minimum safe distance from the postulated explosion to plant structures:

$$R \geq kW^{(1/3)}$$

where R is measured in feet, W is measured in pounds mass, and k = 45.

This formula is based on the postulated explosion producing a peak positive incident overpressure on plant structures of 1 psi, a value at which no significant damage to the structures is assumed to occur.

With regard to the evaluation of an explosion of a railroad car on the Burlington Northern Railroad, the value of 132,000 for W is substituted in the formula to yield a value for minimum safe distance R of 2291 feet, which is less than the actual distance of 2 miles (10,560 feet). Therefore it can be concluded that the postulated explosion of a railroad car on the Burlington Northern Railroad presents no hazard to the PINGP.

With regard to the Soo Line Railroad, the 2291 feet minimum safe distance R exceeds the actual distance of 0.2 miles (1,056 feet). However, PINGP USAR Section 2.9.2, "Postulated Explosion of

Munitions Barge", states that analyses have demonstrated that an overpressure of 2.25 psi resulting from a postulated barge explosion would be acceptable. The USAR states that some damage may be expected to occur to light external structures for such an event, but that this would be consistent with the intent of the design for these structures with regard to tornado forces.

Therefore if both sides of the formula are divided by R, the result is:

$$1 = \frac{45\ W^{(1/3)}}{R}$$

which expresses peak positive incident overpressure in terms of W and R.

If values of 132,000 and 1056 are then substituted for W and R, respectively, the result is:

$$\frac{45\ (132{,}000)^{(1/3)}}{1056} = 2.17$$

This indicates that an explosion of 132,000 pounds mass at a distance of 1056 feet will result in a peak positive incident overpressure on plant structures of 2.17 psi. Since it has been demonstrated that an overpressure of 2.25 psi would be acceptable, it is concluded that the postulated explosion of a railroad car on the Soo Line presents no hazard to the PINGP.

With regard to the effects of toxic chemicals, the PINGP Control Room Habitability Toxic Chemical Study [16] determined that two chemicals, chlorine and anhydrous ammonia, shipped by the SOO Line Railroad, could potentially present a hazard to the control room operators. However, according to the results of calculations ("PINGP Toxic Chemical Analysis - Chlorine and Ammonia Probability Analysis" [18], and "PINGP Toxic Chemical Analysis - Revised Chlorine and Ammonia Spill Estimates" [19], it was determined that the probability of a SOO Line Railroad railcar accident releasing chlorine that would incapacitate control room operators was 1.16×10^{-7} per year. These calculations also determined that the probability of a similar railcar accident releasing ammonia would be 1.47×10^{-7} per year, which is less than the Regulatory Guide 1.91 criterion of <1E-6 per year for offsite hazardous releases. Therefore it is concluded that toxic chemical shipment by rail does not pose a hazard to the PINGP, based on the low probability of occurrence of this event.

C.2.4.5 Truck Accidents

Truck accidents pose a hazard to a nuclear power plant due to the possible release of hazardous material toward the plant and/or the possibility of explosion and fire, with resulting physical damage to the plant due to blast, debris and fire. Physical damage to a plant due to actual collision

with plant structures is considered minimal due to the distance between main highways and plant structures.

At the PINGP, the movement of trucks carrying hazardous materials inside the exclusion area is infrequent and controlled, and only a limited amount of hazardous materials is carried in each shipment. Further, the combination of a heightened level of caution onsite when such a delivery is made (e.g. security inspection and escort, scheduled delivery), along with the low level of truck accident precursors (e.g., negligible traffic, slow speed when inside the gates, non-explosive material) makes the likelihood of such an event very small.

With regard to the effects of toxic chemicals, the PINGP Control Room Habitability Toxic Chemical Study [16] evaluated traffic within a five-mile radius of the site. The study states that only one major highway, Highway 61, is within that radius. The study concluded that frequent hazardous materials shipments along Highway 61 are not anticipated, but would occur instead along major interstate routes. Also, according to this study, the City of Red Wing Fire Department has indicated that no accidents involving a truck carrying hazardous materials on Highway 61 has occurred in over 10 years. Therefore it is concluded that toxic chemical shipment by truck does not pose a hazard to the site.

With regard to potential truck explosions, and using the data collected for the PINGP Control Room Habitability Toxic Chemical Study, it is concluded that shipments of hazardous materials on Highway 61, the only major highway within the five-mile radius of the plant, would be very infrequent. Hazardous material shipments of any significant frequency would occur on the interstate highways beyond the five mile radius. Therefore, truck explosions do not pose a hazard to the site.

Based on the above analyses it is concluded that truck accidents have no impact on the safe operation of the PINGP.

C.2.4.6 Nearby Industrial Facilities

The nearest industrial center to the PINGP site is the city of Red Wing, Minnesota, located approximately 3-4 miles from the site. In evaluating toxic hazards to the site, the PINGP Control Room Habitability Toxic Chemical Study obtained information regarding nearby industrial facilities located in the Red Wing area. That list is reproduced below:

Table C.3
City of Red Wing Major Industry

Employer	Products/Services	Employees
Red Wing Shoe Company	Work Shoes and Boots	1040
Northern States Power Co.	Utilities	676
Josten's Diploma Division	Diplomas, Plaques	325
St. John's Hospital	Medical	322
F.L. Meyer Industries	Transmission Poles	288
S.B. Foot Tanning Co.	Leather Processing	280
Durkee-Atwood	Rubber Products	262
Red Wing Health Center	Medical	231
Interstate Medical Center	Medical	191
Riviera Cabinets	Kitchen Cabinets	170
St. James Hotel	Food & Lodging	153
Riedell Shoes, Inc.	Sports Footwear	130
Central Research	Manufacturing Mechanical Arms	58
RAM Control Inc.	Robotics	55

Although these industries are in the vicinity of Prairie Island (some are within a five-mile radius of the plant), it is concluded, based upon their size and the nature of their products, that they create no hazard to the PINGP site as a result of potential explosion or fire.

With regard to the effects of toxic chemicals, the PINGP Control Room Habitability Toxic Chemical Study evaluated the industrial facilities in the City of Red Wing and concluded that, based on the size of the industries, and the types of products and services produced by these industries, that the hazardous chemicals used by nearby industrial facilities pose no hazard to the safe operation of the PINGP.

Therefore it is concluded that accidents from nearby industrial facilities would not impact the safe operation of the PINGP.

C.2.4.7 Nearby Military Facilities

According to PINGP USAR Section 2.2.4.4, Nearby Industrial, Transportation, and Military Facilities, there are no military facilities within 5 miles of the Prairie Island site. Therefore, this potential contributor to risk can be eliminated.

C.2.4.8 Hazardous Material Releases from On-Site Storage

The PINGP Control Room Habitability Toxic Chemical Study [16] was performed to assess the need for toxic chemical detectors at the site. The study consisted of the following steps:

- Define the appropriate regulatory requirements;
- Perform a survey to identify hazardous materials;
- Develop a toxic chemical spill analysis model;
- Define incapacitation assessment criteria; and
- Assess the effects of toxic chemical spills on control room operators.

The study included an evaluation of toxic materials stored on site. This study determined that eight hazardous chemicals were stored onsite that exceeded the Superfund Amendments and Reauthorization Act (SARA) reportable limits:

- Sulfuric acid (maximum capacity 5,000 gal.)
- Diesel fuel #2 (maximum capacity 142,000 gal.)
- Boric acid (maximum capacity 36,000 lbs.)
- Liquid nitrogen (maximum capacity 3,000 gal.)
- Sodium hydroxide (maximum capacity 5,000 gal.)
- Hydrazine 35% (maximum capacity 250 gal.)
- Sodium bromide (maximum capacity 400 gal.)
- Sodium hypochlorite (maximum capacity 1,142 gal.)

Four of these chemicals (boric acid, liquid nitrogen, sodium bromide, and sodium hypochlorite) were eliminated from further consideration because they are not identified by 29CFR1910, the National Institute for Occupational Safety and Health, or the American Conference on Governmental Industrial Hygienists as being toxic.

Of the four remaining chemicals, three (sulfuric acid, hydrazine, and sodium hydroxide) were eliminated from further consideration since they were evaluated in the original toxic study issued in 1981 and found at that time to pose no threat to Control Room operation. With the exception

of hydrazine, these chemicals are stored in the same locations and quantities as they were when they were evaluated in the 1981 study. Although current hydrazine storage is 250 gallons, it is now stored much farther from the Control Room ventilation intake and therefore is eliminated from further consideration.

The one remaining chemical stored on-site requiring consideration was diesel fuel oil. The majority of the fuel oil at the site is stored underground and, therefore, presents no real hazard. A rupture of the underground tank would result in ground seepage of the fuel oil and not vapor release. There are also a small number of day tanks located within plant structures. These are of much smaller volume. The hazard presented by these day tanks would be as a source of flammable material. The Internal Fires IPEEE (Appendix B) accounts for these tanks in its assessment of the potential increase to plant risk caused by combustibles located onsite. Therefore, the study eliminated fuel oil from further consideration.

Therefore the Control Room Habitability Toxic Chemical Study concluded that no toxic chemical poses a hazard to Control Room operation. Based on these results, it is concluded that accidents from chemical releases from on-site storage would not impact the safe operation of the PINGP.

C.3 CONCLUSIONS

Based upon the evaluations presented in Section C.2, we conclude that there is no external event other than fire and seismic that may be a safety concern to the Prairie Island Nuclear Generating Plant. No vulnerabilities were identified and the screening criteria contained in NUREG-1407 and Generic Letter 88-20, Supplement 4, are satisfied for all events.

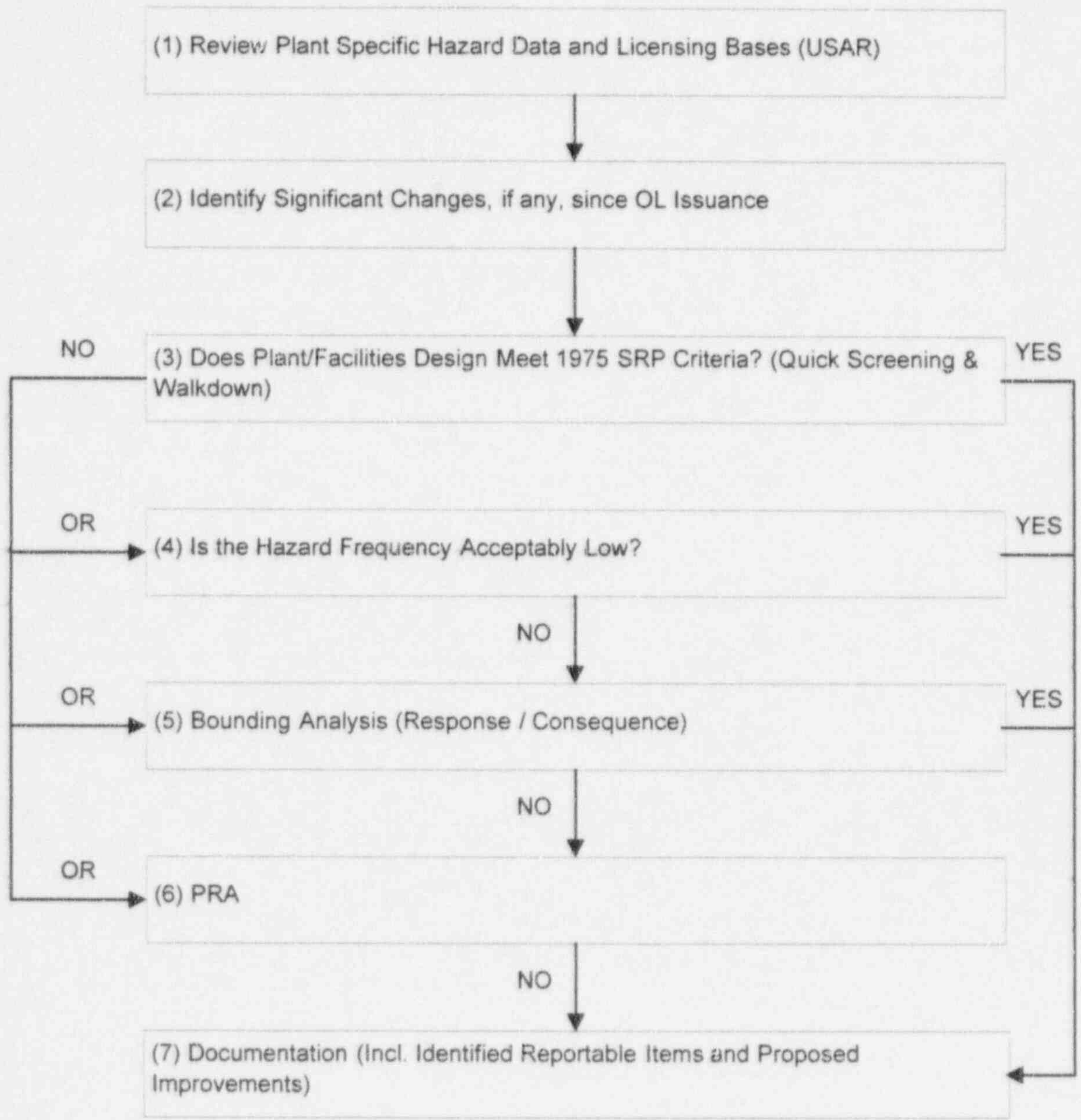

Figure C.1
Flow Chart of IPEEE Screening Process For External Events Other Than Seismic and Fire

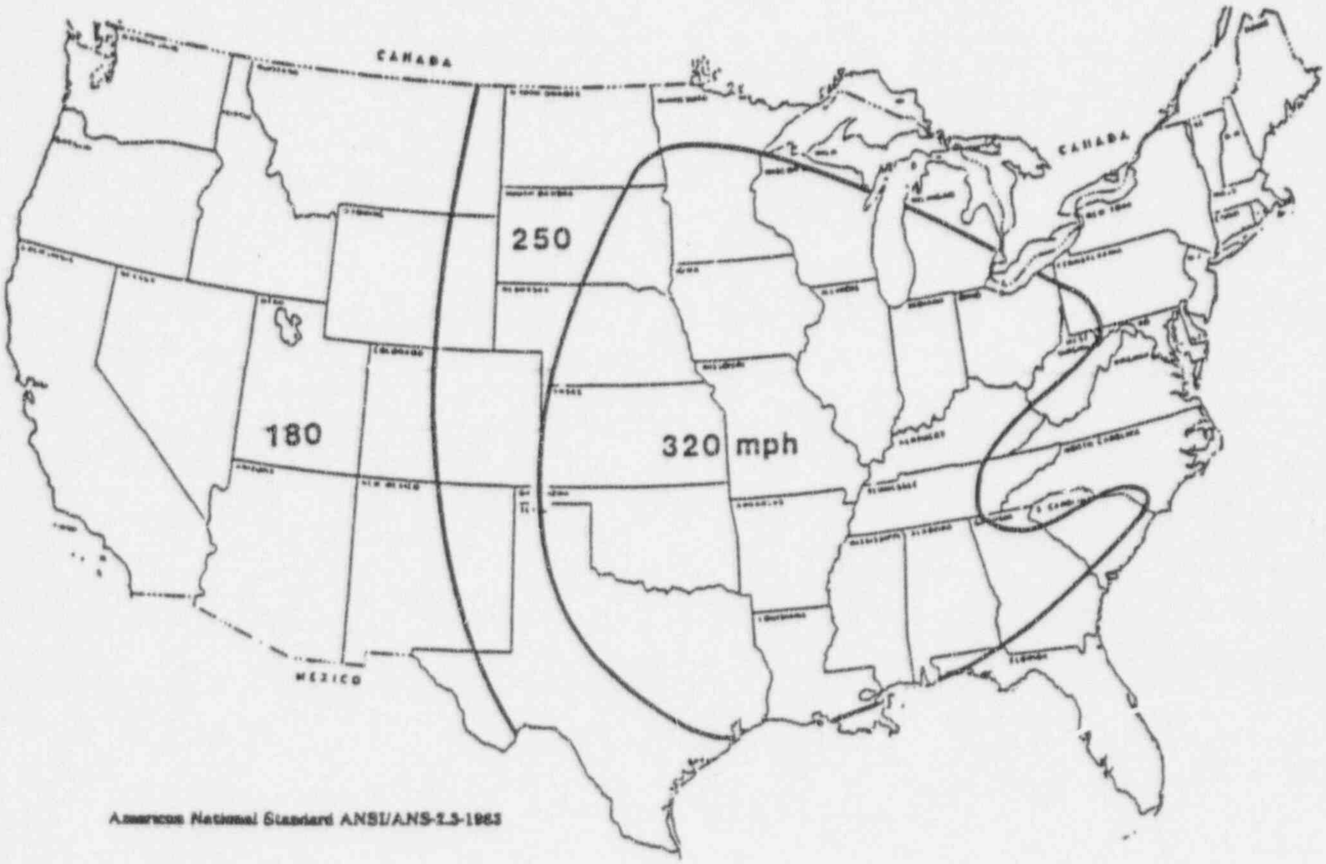

Figure C.2
Tornadic Windspeeds Corresponding to a Probability of 10^{-7} Per Year

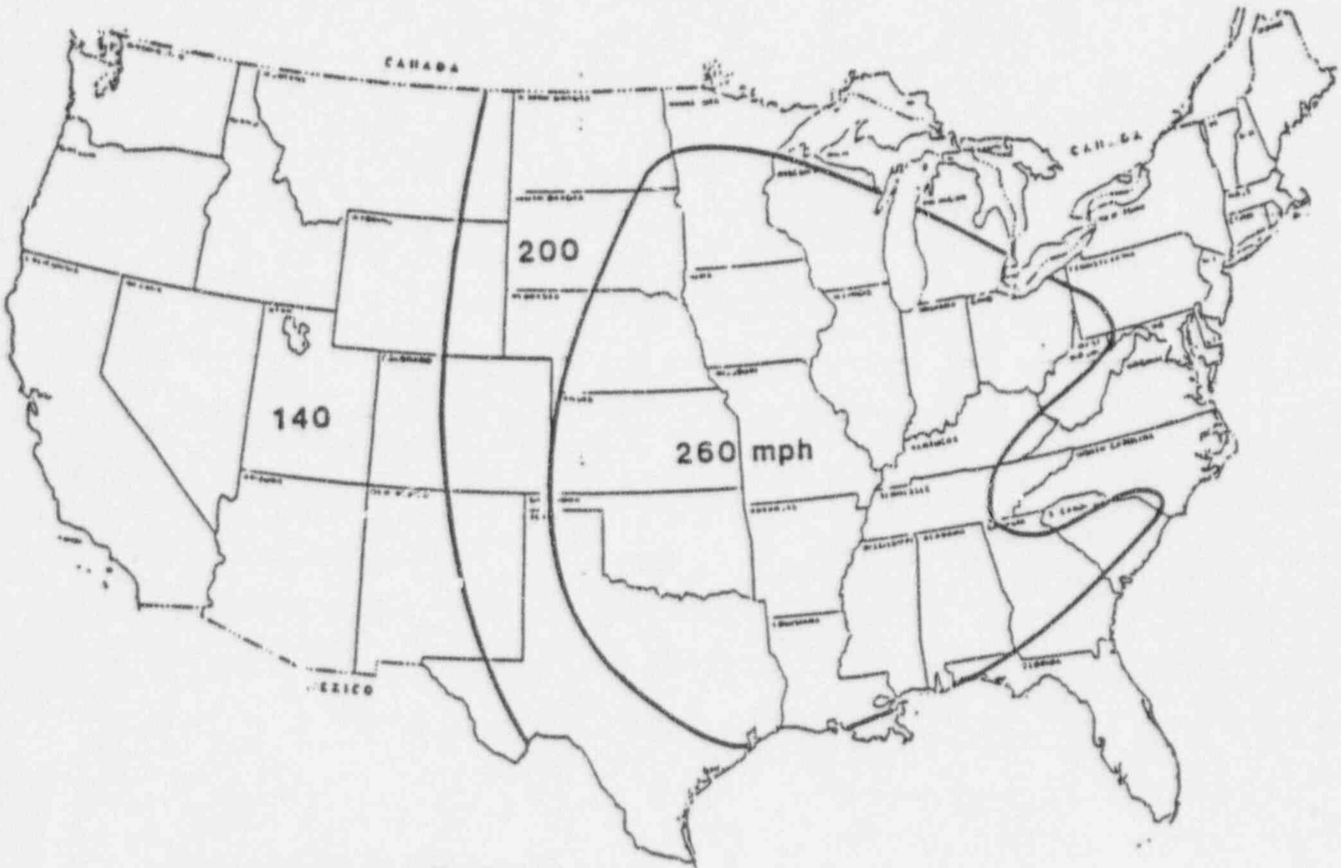

Figure C.3
Tornadic Windspeeds Corresponding to a Probability of 10^{-6} Per Year

C.4 REFERENCES

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2. Generic Letter 89-22, "Potential for Increased Roof Loads and Plant Area Flood Runoff Depth at Licensed Nuclear Power Plants due to Recent Change in Probable Maximum Precipitation Criteria Developed by the National Weather Service", October 19, 1989.

3. NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities", June 1991.

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5. NUREG/CR-5042, Supplement 2, "Evaluation of External Hazards to Nuclear Power Plants in the United States, Other External Events", February 1989.

6. NUREG-75/087, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants", September 1975.

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8. USNRC Regulatory Guide 1.76, "Design Basis Tornado for Nuclear Power Plants", April 1974.

9. USNRC Regulatory Guide 1.78, "Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release", June 1974.

10. USNRC Regulatory Guide 1.91, "Evaluations of Explosions Postulated to Occur on Transportation Routes Near Nuclear Power Plants", Revision 1, February 1978.

11. USNRC Regulatory Guide 1.95, "Protection of Nuclear Power Plant Control Room Operators Against an Accidental Chlorine Release", Revision 1, January 1977.

12. USNRC Regulatory Guide 1.102, "Flood Protection for Nuclear Power Plants", Revision 1, September 1976.

13. USNRC Regulatory Guide 1.117, "Tornado Design Classification", Revision 1, April 1978.

14. PINGP Updated Safety Analysis Report, Rev. 7, December 1988.

15. PINGP USAR Appendix F, "Probable Maximum Flood Study Mississippi River at Prairie Island, Minnesota", incorporated into USAR Revision 4, December 1985.

16. Northern States Power Company Prairie Island Nuclear Generating Plant Control Room Habitability Toxic Chemical Study, Revision 1, December 11, 1991.

17. PINGP Calculation GEN-PI-005, "Tornado and Seismic Evaluation of D1 and D2 Components (HVAC Duct, Exhaust Piping, & Door)".

18. TENERA Calculation 1934-2.2-005, "PINGP Toxic Chemical Analysis - Chlorine and Ammonia Probability Analysis".

19. TENERA Calculation 1934-2.2-006, "PINGP Toxic Chemical Analysis - Revised Chlorine and Ammonia Spill Estimates".

20. Transactions of the American Society of Civil Engineer's Paper ASCE 3269, "Wind Forces on Structures", Volume 126, Part II (1961).

21. ANSI/ANS-2.3-1983, "Standard for Estimating Tornado and Extreme Wind Characteristics at Nuclear Power Sites", American Nuclear Society, 1983.

22. PINGP Abnormal Procedure AB-2, "Tornadoes", Revision 9, October 21, 1994.

23. PINGP Abnormal Procedure AB-4, "Flood", Revision 9, April 12, 1993.

24. PINGP Operating Procedure C25, "Circulating Water System", Revision 13.

25. Non-Modification Safety Evaluation No. 427, "Cooling Water Emergency Intake Line Capacity", November 21, 1995.

26. U. S. Department of Transportation Federal Aviation Administration letter, B. Wagoner to R. Newman, dated August 29, 1996.

27. PINGP Reportable Occurrence Report RO-78-18, date of event 9/12/78.

28. PINGP Reportable Occurrence Report RO-80-20, date of event 7/15/80.

29. PINGP Trip Report for Unit 2, date of trip 9/12/82.

30. Prairie Island Nuclear Projects Department Follow-On Item No. A0686, "Documentation of Adequate Lightning Protection."