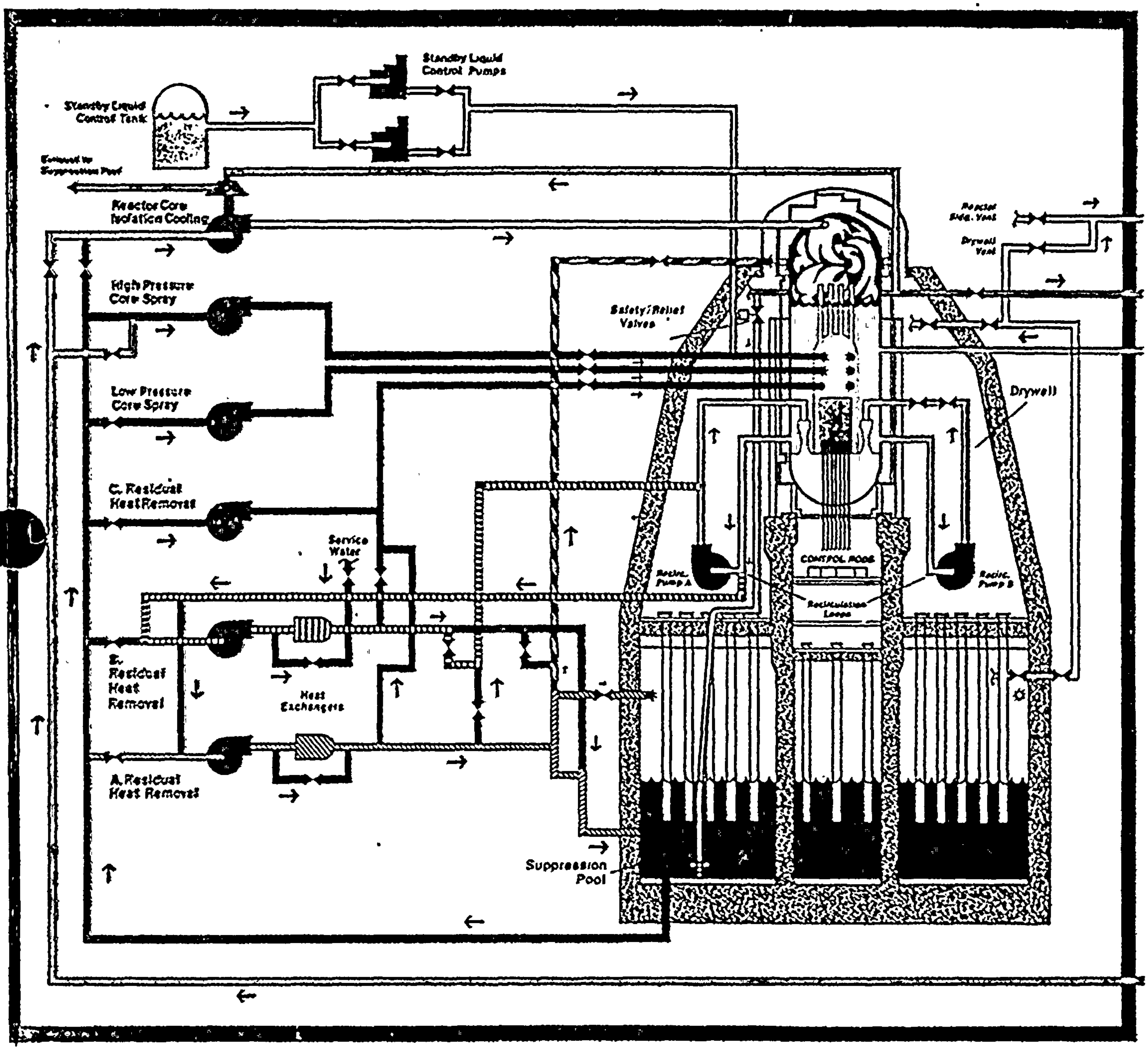
NINE MILE POINT
NUCLEAR STATION - UNIT 2



INDIVIDUAL PLANT EXAMINATION
For EXTERNAL EVENTS
(IPEEE)

NINE MILE POINT NUCLEAR STATION - UNIT 2
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NIAGARA MOHAWK

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List of Acronyms

ADS	Automatic Depressurization System
AOV	Air Operated Valve
APRM	Average Power Range Monitor
ATWS	Anticipated Transient Without SCRAM
BWR	Boiling Water Reactor
CBD	Cable Block Diagram
CDF	Core Damage Frequency
CDFM	Conservative Deterministic Failure Margin
CFS	Cubic Feet Per Second
CR	Control Room
CRD	Control Rod Drive
CRF	Control Room Fire
CRS	Cable Raceway System
CST	Condensate Storage Tank
CV	Containment Venting
DER	Deviation / Event Report
DHR	Decay Heat Removal
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
FA	Fire Area
FIVE	Fire Induced Vulnerability Evaluation
FMEA	Failure Modes and Effects Analysis
FPRA	Fire Probabilistic Risk Assessment
FRS	Floor Response Sprectra
FWS or FW	Feedwater System
GDC	General Design Criteria
GE	General Electric
GERS	Generic Equipment Response Spectrum
GET	General Employee Training
GI	Generic Issue
GRS	Ground Response Sprectra
HCLPF	High Confidence Low Probability of Failure
HPCS	High Pressure Core Spray
HRA	Human Reliability Analysis
HRR	Heat Release Rate
HVAC	Heating, Ventilation, and Air Conditioning
IAS	Instrument Air System
IEEE	Institute of Electrical and Electronic Engineers
IN	NRC Information Notice
INJ	Injection - Reactor Inventory Control
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination of External Events

List of Acronyms

JB	Junction Box
LLNL	Lawrence Livermore National Laboratory
LOCA	Loss of Coolant Accident
LOSP	Loss of Offsite Power
LPCI	Low Pressure Coolant Injection
LPCS	Low Pressure Core Spray
LPI	Low Pressure Injection
MCC	Motor Control Center
MEL	NMP2 Master Equipment List
MOD	Motor Operated Disconnect
MOV	Motor Operated Valve
MSIV	Main Steam Isolation Valve
NFPA	National Fire Protection Association
NIST	National Institute for Standards and Technology
NMP1	Nine Mile Point Unit 1
NMP2	Nine Mile Point Unit 2
NMPC	Niagara Mohawk Power Corporation
NRC	United States Nuclear Regulatory Commission
NSRV	No Stuck Open Safety Relief Valve
NYPA	New York Power Authority
OL	Operating License
OP	Operating Procedure
P&ID	Piping & Instrument Diagram
PGA	Peak Ground Acceleration
PGCC	Power Generation Control Complex
PMF	Probable Maximum Flood
PMP	Probable Maximum Precipitation
PRA	Probabilistic Risk Assessment
PWR	Pressurized Water Reactor
RBCLC	Reactor Building Closed Loop Cooling
RCIC	Reactor Core Isolation Cooling
RCPB	Reactor Coolant Pressure Boundary
RHR	Residual Heat Removal
RISKMAN	PLG, Inc. PRA Workstation Software
RLE	Review Level Earthquake
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RS	Response Sprectra
RSP	Remote Shutdown Panel
RSS	Remote Shutdown System
SDC	Shutdown Cooling
SER	Safety Evaluation Report.
SEWS	Screening Evaluation Work Sheets
SLC	Standby Liquid Control

List of Acronyms

SMA	Seismic Margins Assessment
SOP	Special Operating Procedure
SOV	Solenoid Operated Valve
SPC	Suppression Pool Cooling
SPRA	Seismic Probabilistic Risk Assessment
SQUG	Seismic Qualification Utility Group
SRP	Standard Review Plan (NUREG-0800)
SRSS	Square Root of the Sum of the Squares
SRT	Seismic Review team
SRV	Safety Relief Valve
SSC	Structures, Systems, and Components
SSE	Safe Shutdown Earthquake
SWEC	Stone & Webster Engineering Corporation
SWP or SW	Service Water System
TBCLC	Turbine Building Closed Loop Cooling
TOL	Thermal Overload
UPS	Uninteruptible Power Supply
USAR	Update Final Safety Analysis Report
USI	Unresolved Safety Issue

1.0 Executive Summary

The Nine Mile Point Unit 2 (NMP2) Individual Plant Examination of External Events (IPEEE) is a systematic evaluation of plant risk utilizing the latest technology available for assessment of external events. In addition to using industry information and information referenced in Generic Letter 88-20, Supplement 4[2] and NUREG-1407[3], the NMP2 IPEEE made extensive use of the NMP2 Individual Plant Examination (IPE)[1].

The IPEEE scope for NMP2 included three classes of external hazards: seismic, fire, and others. The other hazards include high winds, flooding, transportation, and nearby industrial facilities. The Seismic Margins Assessment (SMA)[11] approach was used for the seismic portion of the analysis. During the SMA, it was noted that performing a full fragility assessment to support a seismic Probabilistic Risk Assessment (PRA) required relatively little additional effort. As such, full fragilities were developed and a seismic PRA was performed in addition to the SMA. The fire portion of the study utilized the Fire Induced Vulnerability Evaluation (FIVE)[25] including the NRC recommended enhancements. However, because few areas were screened in the early portion of the FIVE analysis, the FIVE assessment became a fire PRA. The others portion of the study utilized the progressive screening approach outlined by the NRC in Generic Letter 88-20, supplement 4 and NUREG-1407.

A figure of merit commonly quoted in PRA type studies is core damage frequency. While this figure does not entirely represent the value of the IPEEE, it is a widely used indicator. The core damage frequency (CDF) calculated in the NMP2 IPE is 3.1×10^{-5} per year. The additional contribution from this study of external events is less than 1E-6/yr from the seismic hazard, approximately 1E-6/yr from fires, and less than 1E-6/yr for other hazards. These results suggest that operation of NMP2 poses no undue risk to the public and is within the range of CDFs for other nuclear plants. In addition to the evaluation of accident sequences that could lead to core damage, the NMP2 IPEEE has also evaluated containment performance. The containment evaluation indicates that the NMP2 containment does not have any unusual characteristics that result in poor containment performance. Another figure of merit that is associated with radionuclide releases is the frequency of an "early large" release. The "early large" radionuclide release frequency calculated in the NMP2 IPE is 8.0×10^{-7} per year. The IPEEE results indicate that the seismic and fire contribution is on the order of 1E-7/yr or less. This frequency also suggests that NMP2 poses no undue risk to the public.

The NRC in the Severe Accident Policy Statement[3] (1985) stated that:

> *On the basis of current available information, the Commission concludes that existing plants pose no undue risk to the public health and safety and sees no present basis for immediate action on generic rule making or other regulatory changes for these plants because of severe accident risk.*

The IPEEE has determined that there are no plant specific or unique features of NMP2 that would alter this generic conclusion.

1.1 Background and Objectives

The NMP2 IPEEE was undertaken in response to Generic Letter 88-20, Supplement 4[2] "Individual Plant Examination for External Events for Severe Accident Vulnerabilities - 10CFR§50.54(f)," dated June 28, 1991. This letter requested that all licensees perform a systematic evaluation of plant risk. Upon subsequent release of NUREG-1407[3] "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," dated June 1991, Niagara Mohawk Power Corp. committed to perform an IPEEE for NMP2 by June 30, 1995. This commitment noted that NMPC would be using the Seismic Margins Methodology (SMA)[11] for the assessment of seismic risk, the FIVE Methodology[25] for the assessment of fire risk, and the NRC progressive screening approach for others evaluation. As discussed later in this report, the SMA and FIVE assessments were extended in scope to comprise full PRAs.

The goals of this project were to:

- ✓ Meet the NRC commitment relating to Generic Letter 88-20, Supplement 4
- ✓ Understand the underlying risks to nuclear plant safety and key sources of uncertainty
- ✓ Identify areas where cost effective risk improvement opportunities exist
- ✓ Supplement the IPE completeness which was developed as a tool to quantify nuclear safety and support a comprehensive risk management program
- ✓ Supplement the in-house risk analysis capability developed from the IPE for application to plant decision-making
- ✓ Develop models capable of extension to shutdown risk assessment

In order to meet the first of the above goals, the generic letter suggested four main objectives similar to the IPE process:

1. Develop an appreciation of severe accident behavior
2. Understand the most likely severe accident sequences that could occur at the plant
3. Gain a qualitative understanding of the overall probabilities of core damage and fission product releases
4. If necessary, reduce the overall likelihood of core damage and fission product releases by modifying hardware and procedures that would help prevent or mitigate severe accidents

In order for NMPC to meet the above goals and objectives, a detailed project plan was developed in early 1991. This plan called for the formation of a team of 6 analysts, a support network of more than 12 members of various plant organizations, an in-house review group, and external consultants. The analysts and the external consultants were primarily involved in the day to day development. The individuals in the IPEEE support organization represented structural, mechanical analysis, fire protection, operations, maintenance, engineering, training, and technical support (system engineers). They were not involved in the actual analysis but provided crucial information on plant operation in the form of answering questions and participating on plant walkdowns.

1.2 Plant Familiarization

Nine Mile Point Nuclear Station Unit 2 (NMP2) is operated by Niagara Mohawk Power Corporation (NMPC). The plant is located on the southeast shore of Lake Ontario, approximately 6.2 miles (10 km) northeast of the city of Oswego. Nine Mile Point Nuclear Station Unit 1 (NMP1), also operated by NMPC, is immediately to the west and shares the site with NMP2. The James A. Fitzpatrick Nuclear Power Plant, operated by the New York Power Authority (NYPA), is immediately east of the Nine Mile Point site.

NMP2 is a General Electric designed Boiling Water Reactor (BWR) Type 2 BWR 5. The rated thermal power level is 3323 MWt corresponding to a 1080 MWe power level. As of this printing, NMPC is in the process of completing a power uprate program which will increase rated thermal power to 3467 MWt. The effect of the uprate program was not considered in the IPEEE (or IPE). The containment is a Mark II type utilizing an over-under suppression design with multiple downcomers connecting the drywell to the wetwell (suppression pool). Eight of the downcomers are located in the containment's sunken pedestal immediately under the reactor.

The unit has three onsite emergency diesel generators. The third of which is dedicated to the High Pressure Core Spray System (HPCS). In addition to HPCS, NMP2 has a Reactor Core Isolation Cooling System (RCIC) that employs a turbine pump powered by reactor steam. The HPCS and RCIC systems are capable of supplying cooling water to the vessel at elevated pressures. The Low Pressure Core Spray (LPCS) and Low Pressure Coolant Injection (LPCI) systems provide a source of cooling water once the reactor has been depressurized. Two trains of Residual Heat Removal (RHR) are capable of injecting to the vessel at low pressures (LPCI mode), spraying the drywell, spraying the wetwell, or injecting to the suppression pool (pool cooling mode). In addition, NMP2 has two significant plant enhancements: an automatically actuated Standby Liquid Control (SLC) system and a hardened containment vent.

The plant would be classified as a relatively "new" plant having initiated commercial operation in 1988. The plant construction included what could be called rigorous and thorough design against seismic, fire, and other external hazards. Design and construction was performed according to the standard review plan (SRP)[7].

To collect up-to-date information and give the analysts a more complete understanding about NMP2, three categories of plant walkdowns were performed for the IPEEE.

1. Seismic (Described in Section 3.1.1)
2. Fire (Described in Section 4.2)
3. Other hazards (Described in Section 5)

1.3 Overall Methodology

The objective to the NMP2 IPEEE is to perform the equivalent of a Level II PRA for external events. As with the NMP2 IPE, initiating events (in this case external hazards), impacts of initiating events on the plant, and the modeling and quantification of core damage frequency is required. The overall methodology is very similar to the IPE as summarized below:

1. Initiating Events - external event hazards analyses provides the initiating events for the IPEEE or external events PRA. For external hazards, the initiating event may have to be assessed for a spectrum of hazard intensities in the form of frequency of exceedance curves or tables (see section 3.2 for seismic hazards). In the case of fires, the frequency is first developed for locations in the plant using the EPRI FIVE[25] methodology. Then, if the initial screening does not demonstrate low risks for the locations, the fire hazard may be evaluated in greater detail by considering different sources (i.e., intensity) and their frequencies.

2. Initiating Event Impacts - as with the IPE, the impact of the hazard on structures, systems, and components (SSCs) is crucial to the assessment. For the seismic and fire hazards, this requires the identification of safe shutdown success paths from the IPE and the SSCs needed to support the success paths. Then, the seismic fragility (failure probability versus seismic intensity) of the SSCs is evaluated which provides the seismic impact on the plant. The fire analysis is similar, except fire hazard impact is assessed at each plant location.

3. Plant Model & Quantification - the unavailability of plant equipment not impacted by the hazard is included in the analysis of core damage frequency by using the IPE model. The hazards are run through the IPE model as initiating events. The event tree top events are requantified and event tree quantification rules are changed to ensure that the hazard impact on the plant is modeled. Other event tree top events not impacted by the hazard still have their normal IPE unavailability modeled. The results are core damage frequency for the seismic and fire initiating events.

4. Containment Performance - this is considered in items 1 through 3 and by comparing quantitatively the potential contribution of external hazards to the IPE results.

The overall methodology is further summarized below for each external hazard:

Seismic Analysis

The NMP2 IPEEE used the EPRI SMA method for seismic risk assessment. In this method, High Confidence Low Probability of Failure (HCLPF) values are determined for components designated in two safe shutdown trains. This identification of components and determining their HCLPF provides most of the information needed to satisfy items 2 through 4 above in a seismic PRA. To further support the goal of obtaining reasonable quantitative insights, the review level earthquake (RLE) used for screening was chosen as 0.5g , rather than 0.3g, as recommended by NUREG-1407. Also, the HCLPF determination was extended to provide seismic fragilities in support of PRA since most of the work necessary to define fragilities was already completed.

EPRI[17] and NRC[18] seismic hazards were available for the NMP site, therefore, these estimates were used for the initiating event portion of the seismic IPEEE (item 1 above). The most significant effort involved the assessment of seismic impacts on SSCs (items 2 and 4 above) which is described in Section 3.1 (seismic margins method). The results of items 1 and 2 were utilized along with the IPE to complete items 3 and 4 and derive quantitative insights with regard to seismic risk (Section 3.2). This was a relatively insignificant effort with all the inputs already available.

Fire Analysis

The NMP2 IPEEE used the FIVE method for fire risk assessment including the NRC recommended revisions to the FIVE methodology. Again, an EPRI[25] data base was available, thus, a limited amount of work was required to establish initial hazard frequencies (item 1 above). Some effort was required to partition the raw data throughout the plant locations. Partitioning considered building type and ignition sources within the location, including equipment. As with the seismic analysis, the most significant effort is associated with determining the impact of fires at each location (item 2 above). In the case of fires, determining the location of cables and then the impact of cable failures is a major part of the analysis. If the location did not screen out using conservative assumptions (i.e., all impacts occur given a fire), the location of cables, conduits, cable trays, and equipment relative to fire sources was required to perform more detailed modeling. Use of the IPE (items 3 and 4) to model fire initiators in the screening analysis and derive quantitative insights was a relatively minor effort in comparison to determining impacts.

Others Analysis

The methodology used to screen high winds, floods, transportation, and nearby facility accidents as insignificant to risk is based on compliance with NRCs standard review plans (SRPs). This approach is outlined in NUREG-1407 and discussed below. The underlying basis for compliance with the SRPs includes consideration of hazard frequency (item 1 above) and plant design (item 2 above).

The methodology utilized for each hazard is described further in Sections 3, 4, and 5.

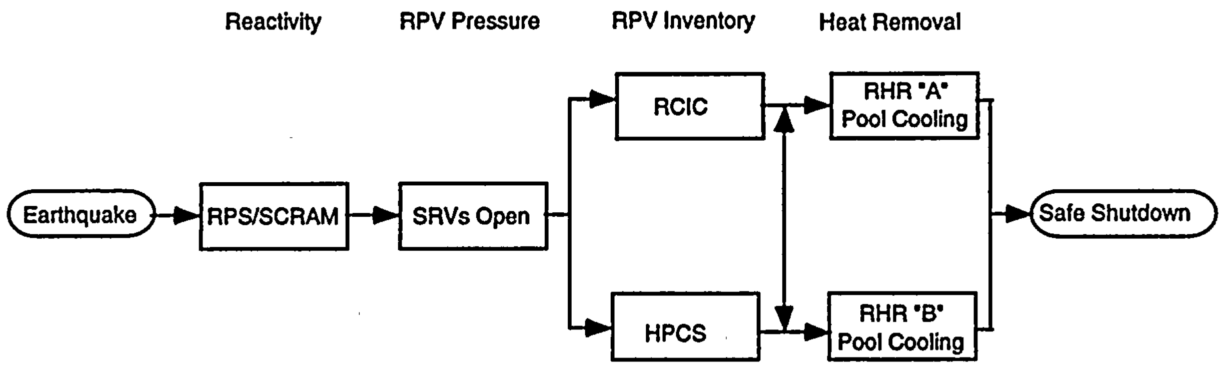
1.4 Summary of Major Findings

With the exception of seismic and fire hazards, all other hazards were screened out utilizing NMP2 compliance with the SRPs. This was straight forward for NMP2, a relatively new plant, which was designed and constructed to meet the SRPs. A combination of hazard frequency and the conditional frequency of plant damage (plant design) ensures that core damage frequency is low. Several studies have demonstrated this and the SRPs require that accident sequences greater than 1E-7/yr be considered as design basis events. Review of the NMP2 analysis in the USAR, the SRPs, and other analyses indicate that the risk from other hazards is low, on the order of 1E-6/yr or less.

For the same reasons described above (i.e., relatively new plant designed to the latest conservative requirements), the detailed analysis of seismic and fire hazards found the risks to be relatively low. Core damage frequency for each hazard was assessed to be on the order of 1E-6/yr or less.

The major findings for each hazard are summarized below:

<u>Seismic Analysis</u>
The review level earthquake (RLE) used for screening was chosen as 0.5g, rather than 0.3g, as recommended by NUREG-1407. Since the seismic capacity of NMP2 was expected to be high, it was determined the 0.5g RLE would provide more knowledge relative to the realistic seismic capability of the plant. The seismic margins assessment (Section 3.1) concluded that structures, systems, and components identified in the simplified success path below screened with a HCLPF (high confidence low probability of failure) equal to or greater than 0.5g.



A seismic PRA was performed to place the seismic margins analysis results into quantitative perspective and support future risk management applications. The seismic PRA model is described in Section 3.2 and the results of the NMP2 seismic PRA are summarized below:

NMP2 Seismic Core Damage Frequency

Core Damage Timing & Containment Status	Mean Annual Frequency	
	EPRI	NUREG
Late (loss of heat removal or injection)	5.9E-8	2.2E-7
Early - isolated containment (loss of injection)	3.2E-8	9.9E-8
Early - unisolated containment (loss of injection)	1.6E-7	9.0E-7
TOTAL	2.5E-7	1.2E-6

The above results (provided for both the EPRI and NUREG hazards at the NMP site) display a relatively low risk from seismic events. This is consistent with the insight that the frequency of a major earthquake is low at the NMP2 site and the seismic capacity of the plant is high (i.e., HCLPF on the order of 0.5g or greater). In addition, these results are conservative as described further in Section 3.2. The early - unisolated containment endstate frequency is dominated by the 0.5g plant HCLPF (i.e., screening level earthquake). In addition, the approach used to convert the SMA HCLPFs to a seismic fragility in the PRA was conservative as explained in Section 3.2.

Containment performance evaluations were included in the SMA studies which considered the primary containment structure, penetrations, piping and valves as well as LOCAs outside containment. The HCLPF for these structures and components is determined to be much higher than the 0.5g plant HCLPF value discussed in the above results. The judgement of the IPE/IPEEE Team is that containment failure is dominated by station blackout scenarios with unisolated penetrations. The annual frequency of these scenarios from this study is 3.7E-9 (1.1E-8 for the NUREG hazard) and includes credit for the operators locally isolating MOVs outside the primary containment. If this credit was removed (guaranteed failure), the frequency of an unisolated containment would be 3.7E-8 (1.1E-7 for the NUREG hazard). Thus, a more reasonable assessment of early large releases is expected to demonstrate a reduction in the above results. A more detailed description of accident sequences and the importance of systems is provided in Section 3.2.

<u>Fire Analysis</u>
With the exception of the control room, all locations were screened out below the 1E-6/yr screening criteria in FIVE. Also, the analysis provides confidence that core damage frequency would be <1E-7/yr for the typical location in the plant with the exception of the control room. The frequency of core damage due to fires in the control room was estimated to be on the order of 1E-6/yr as discussed in Section 4.6.

The reason for this low quantified fire risk can be summarized by the following findings:

1. A detailed analysis of fire impacts was performed utilizing the IPE, including balance

of plant systems. This more detailed consideration of success paths led to early screening (initial conservative screening) of most locations.

2. Detailed assessment screened out those locations that did not pass the initial screening, primarily due to two important factors.

   - Equipment and cables are spatially separated. For example, close examination of fire area 88 (corridor in the control building El 261) found cables associated with the emergency diesel located at the opposite end of the corridor from where offsite power and balance of plant cables are located.

   - Automatic detection and suppression. For example, fire area 88 has automatic detection and water spray suppression in the cable trays that contain offsite power and balance of plant cables. There is no automatic suppression at the other end of the corridor where the emergency diesel cable is located.

3. Design of the control room, relay room, and cable spreading areas significantly limits the risk from fires. The design of the control complex includes steel floor sections, termination cabinets, and panels[40]. The steel floor sections are designed to prevent fires from initiating, prevent propagation in the unlikely event of a fire, and allow easy access for quick suppression of fires. The termination cabinets contain only cables, thus the frequency of a fire in these cabinets should be less than the frequency of fires in electrical panels in the control and relay rooms which contain relays, lights, and other electrical equipment. All termination cabinets have bays (typically 4) that are separated by 3/16 inch steel plate. Each bay has a smoke detector.

   All cables were tested in accordance with IEEE 383. TEFZEL insulated cables are used which have been proven by test to be difficult to ignite and are non-propagating. Smoke generation is also insignificant.

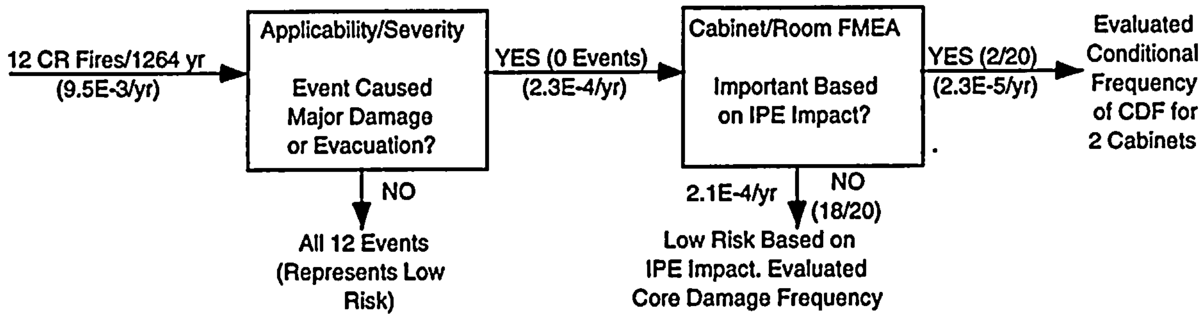
   Floor sections are designed to limit the flow of air and exhaust gases by sealing all penetrations. This limits oxygen and eliminates air flow, thus preventing a fire from spreading. The design also includes a fixed Halon suppression system.

   In general, electrical separation criteria does not allow Division I, II, III, or black (non divisional) cables within the same floor section or termination cabinet section. The location of important support system cables (offsite power, Divisional AC power and service water) at termination cabinets and panels was reviewed along with their routing within the floor sections. It was determined that these cables are routed separately. This determination and the above design indicates that the risk of fires in the floor sections and termination cabinets is small and can be screened out.

The frequency of fires in non termination cabinets is higher and the spatial location of cables within these panels envelope the spatial proximity of important cables in the control room.

The main control panels in the control room were determined to represent the greatest risk from fires. In order to realistically estimate core damage frequency (CDF) for fires in this area, the routing of cables through the area was evaluated as well as the impact of fires in specific electrical cabinets. In addition, the fire events that have occurred in the database were evaluated to develop a more realistic estimate of a fire initiator that causes major damage. The following figure summarizes this evaluation.

Control Room (CR) Fire Evaluation



As shown above, none of the 12 events in the database resulted in major damage or the evacuation of a control room. To estimate the frequency of a fire that causes major damage and potential evacuation of the control room, zero events in 1264 years was used to update a prior distribution that enveloped the uncertainty of this event. Then, based on an evaluation of cable routing, the likelihood of cable fires versus cabinet fires, the separation of cables, the PGCC design, and detection and suppression capabilities, it was determined that two main control panels dominate the potential risk of fires based on IPE impact. These two panels were evaluated to assess the frequency of core damage given a fire with the potential of causing major damage and control room evacuation. Fires that have less of an impact on the IPE are about an order of magnitude more likely and they were also evaluated to provide confidence that CDF from these scenarios are at least on the same order of magnitude as those evaluated for the two panels.

The following summarizes the control room evaluation results:

Fire Scenario		CDF Results (Annual Frequency)			
Description	Annual Frequency	Baseline	Sens 1	Sens 2	Sens 1&2
Less Significant Fires	2.1E-04	6.2E-07	1.0E-06	4.3E-06	5.3E-06
CRF1 - Panel 852	1.1E-05	3.5E-07	8.9E-07	4.4E-07	1.5E-06
CRF2 - Panel 852	1.1E-05	2.2E-07	2.5E-07	2.2E-07	2.5E-07
CRF3 - Panel 601	1.1E-05	1.7E-07	2.0E-07	2.2E-07	2.8E-07
Total	2.4E-04	1.4E-06	2.3E-06	5.2E-06	7.3E-06

Each of the above fire scenarios are described in detail in Section 4.6.2. The following provides a brief explanation for the reader:

Less Significant Fires - Low risk based on IPE impact (Section 4.6.2)

CRF1 - Fire in panel 852, loss of offsite power scenario 1 (Section 4.6.2 and Figure 4.6-1)

CRF2 - Fire in panel 852, loss of offsite power scenario 2 (Section 4.6.2 and Figure 4.6-2)

CRF3 - Fire in panel 601, loss of service water (Section 4.6.2 and Figure 4.6-3)

The sensitivity cases were quantified to assess the impact of uncertainties in procedures and human response to fires in the control room which were judged to dominate the results. Sensitivity case 1 assesses importance of operator reliability at the remote shutdown panels when emergency depressurization is required. This case assesses the increase in core damage frequency if no credit is taken for operator response when high pressure injection fails (procedures were developed for 10CFR50 Appendix R scenario which does not require emergency depressurization). Sensitivity case 2 assesses the importance of the decision to evacuate the control room. It is assumed that operators always evacuate the control room and utilize the remote shutdown room. Sensitivity case 3 combines both cases 1 and 2. Each of these sensitivity cases are described below. One reason for these sensitivity cases has to do with limitations with existing procedures when evaluating scenarios beyond the design basis. These limitations are also summarized below.

Sensitivity case 1 sets human recovery to guaranteed failure when the operators initially invoke the remote shutdown procedure N2-SOP-78[39] and high pressure injection (RCIC and HPCS) is unavailable. No credit is given to RCIC when there is a stuck open safety relief valve (SRV). This sensitivity case was provided because SOP-78 is an event driven procedure and emergency depressurization is an event outside the procedure. The model takes credit for the operators returning to symptom based training when these conditions outside the SOP-78 procedure occur. It should be pointed out that the simplified model for "Less Significant Fires" takes no credit for condensate and feedwater systems continuing to provide reactor level control. Therefore, more detailed analysis would be required before drawing conclusions about the importance of emergency depressurization and SOP-78.

Sensitivity case 2 sets the probability that operators initially invoke SOP-78 to 1.0. This allows no chance for the operators to remain in the control room. Typically, human reliability is better in the control room particularly when emergency depressurization is needed. There was no change in core damage frequency (CDF) for scenario CRF2 because the fire impact requires the operators to leave the control room in order to recover. For this reason, the human reliability is expected to be better (i.e., CDF decrease) when the operators initially go to SOP-78, but human reliability was assumed not to change in the analysis.

Although the risks were assessed to be relatively low, some potential limitations were identified with the existing procedures which taken together could be important (the above sensitivity cases were utilized to assess their importance):

- Control Room Evacuation - the symptoms for control room evacuation suggest that a relatively insignificant event could lead to evacuation. This creates uncertainty with regard to what conditions really lead to evacuation. From experience and informal discussions with operations personnel, the perception is that evacuating the control room would be a last resort and the operators would utilize air packs. In most cases, the control room is the preferred location for plant recovery.

- Control Room versus Remote Shutdown Panel (RSP) - once SOP-78 is entered, one interpretation would be that the control room is evacuated. In reality, it is possible that the operators would want to use the RSP to enhance plant recovery (i.e., long term heat removal) while remaining in the control room. To give up control of reactor inventory and other short term critical functions to the RSP may not be appropriate if only long term heat removal is impacted by the fire. Thus, recovery from a control room fire should consider having the flexibility to utilize both the control room and the remote shutdown panels under certain conditions.

- RSP & SOP - given that SOP-78 is required and is being used, it is possible to be outside the event driven procedure. For example, the procedures do not address reactor depressurization and low pressure injection (i.e., a stuck open SRV or RCIC unavailable) or explicitly indicate whether the EOPs can be used (i.e., symptom based procedure).

- Disabling Balance of Plant - given that SOP-78 is entered, procedures have operators close MSIVs and trip main feedwater pumps among other things before leaving the control room. This may not be appropriate depending on the actual fire impacts.

These sensitivity studies show that some safety benefit could be obtained by modifying SOP-78. In particular, more explicit guidance on conditions warranting control room evacuation and use of alternate success paths in the remote shutdown rooms would be beneficial. The possibility of enhancing procedures and training for fires in the control room is being considered.

<u>Other Hazards Analysis</u>
High winds, floods and other external hazards were screened based on a review of plant against Standard review Plan (SRP)[7]. A combination of hazard frequency beyond the design basis and the conditional frequency of core damage given the hazard ensure that core damage frequency is less than 1E-6. Section 5 describes this analysis in greater detail.

2.0 Examination Description

Nine Mile Point Unit 2 (NMP2) IPEEE was undertaken in response to Generic Letter 88-20, Supplement 4[2]. This Generic Letter, issued June 28, 1991, requested all licensees to perform a systematic evaluation of plant risk caused by external events. From the Generic Letter, the general purpose of the IPEEE is to:

- develop an understanding of severe accident behavior
- understand the most likely severe accident sequences that could occur at its plant under full operating conditions
- gain a qualitative understanding of the overall likelihood of core damage and radioactive material release
- and, if necessary, reduce the overall likelihood of core damage and radioactive material releases by modifying hardware and procedures that would help prevent or mitigate severe accidents.

The scope of work is part of the NRC efforts on severe accident closure[57]. In this regard, the IPEEE is a follow-on effort to the recently completed Individual Plant examination (IPE). As an analysis, IPEEE is essentially an addition in scope over IPE such that events external to the plant are evaluated. Following the IPEEE, in terms of severe accident closure, is the program to develop Accident Management capabilities.

2.1 Introduction

The IPEEE is an evaluation that focuses on nuclear plant risk caused by external events. External events are, in general terms, events that originate outside the plant which may affect structures and components within the plant. In Generic Letter 88-20, supplement 4, NRC defined the external events requiring analysis as:

- Seismic events
- Internal fires
- High winds and tornados
- External floods
- Transportation and nearby facility accidents.

Note that internal fires were included with IPEEE rather than IPE even though it would more properly be classified as an internally initiated event.

The generic letter requested that the IPEEE be completed by June 28, 1995 and be performed using the guidance in NUREG-1407[3].

2.2 Conformance with Generic Letter and Supporting Material

The NMP2 IPEEE has been completed in accordance with Generic Letter 88-20, supplement 4 and NUREG-1407. Methods endorsed in these documents were used as discussed in the following section and, in more detail, in sections 3, 4 and 5. NMPC formed a diverse IPEEE team comprised primarily of NMPC staff to perform the analysis . Due to the high degree of involvement by NMPC staff, NMPC expects to derive the maximum benefit from the analysis. Technical adequacy and the IPEEE review process are discussed in Section 6.

Individual interpretations of generic letter 88-20 and NUREG-1407 guidance are noted throughout the submittal, where appropriate.

NMPC made a slight alteration to the NRC proposed IPEEE Table of Contents that should be noted here. This exception was necessary since NMPC performed a Seismic Margins Assessing (SMA)[11] <u>and</u> a seismic PRA (SPRA). Section 3.2 was added to include the SPRA and the USI/Other seismic safety issues section was included as Section 3.3. The generic letter and NUREG-1407 indicated that either SMA or SPRA could be used. Also, in its original response to Generic Letter 88-20 supplement 4, NMPC committed to using the SMA method for seismic analysis. During the process of the SMA, NMPC noted that a SPRA could be performed for very little additional cost. Since the SPRA provides additional information regarding plant risk, and may be a useful tool in the future, it was decided to include the SPRA in the NMP2 IPEEE scope.

While the SMA is the principle focus for meeting the IPEEE commitment, it was deemed valuable to include the SPRA information.

2.3 General Methodology

The list of external events above was broken into three groups: seismic, fire, and others. Each of these groups was assessed using a different analytical methodology. For seismic, the SMA was used. For fire, a fire PRA was performed utilizing the Fire Induced Vulnerability Evaluation (FIVE)[25] methodology as a reference. For the others, the screening approach from NUREG-1407 was used. Each of these will be discussed in a little more detail in the remainder of this section and in greater detail as appropriate in Sections 3,4, and 5.

2.3.1 Fire Methodology Overview

As part of the original response to Generic Letter 88-20 supplement 4, NMPC committed to perform a FIVE analysis. However, in performing the FIVE assessment, NMPC became aware that a fire PRA was necessary. While NMPC has completed the scope of the FIVE analysis, per our commitment, it was deemed necessary to complete a fire PRA in order to complete the scope of the fire IPEEE. This occurred due to a number of reasons.

Once the FIVE was underway, it became evident that the qualitative screening criteria of FIVE was potentially non-conservative due to its treatment of initiating events and non-safety equipment. NMPC was concerned about screening fire areas without safe shutdown equipment. The principle concern with this was the potential for these areas to contain significant plant initiating events. As such, the qualitative screening phase of FIVE became simply an information collection exercise and no areas were screened without identifying the location of non-Appendix R cables that could cause a plant initiating event. Concerns similar to these were raised by NRC during its FIVE review and improvements were made in Revision 1 of FIVE. The latest revision of FIVE was used by NMPC.

In addition, the Appendix R safety shutdown success paths were not detailed enough to quantitatively screen compartments. Thus, non-Appendix R components required review prior to any screening.

The above considerations led NMPC to conclude that quantitative analysis, using the IPE, should be the basis for screening. The IPE contains all the success paths but required augmentation in terms of fire impacts on IPE scope components.

Of further benefit, the fire PRA provides a quantitative tool which enables NMPC to efficiently deal with future fire risk related issues. This is not to suggest that FIVE is not a valuable tool. The FIVE methodology was used extensively for information collection activities, fire hazard analyses, walkdowns, fire growth and propagation analyses, fire detection and suppression assessment, and other fire IPEEE tasks.

Overall, the NMP2 fire PRA is developed similar to other fire PRAs and FIVE analyses. The first phase is an information collection phase: fire areas are delineated and the plant effect for each fire area is determined. The fire compartments were delineated in the same manner as used for the Appendix R analysis. While this was a simple undertaking, the plant effect of a fire in each fire area was difficult to determine. The listing of equipment that may be damaged in a fire area was straight forward but determining the effect of cable damage within a fire area required some effort. In order to fully determine the effect of a fire in a given fire area, each of the cables in the area must be studied. This is necessary since a piece of equipment, even if it is not in the given area, may have an associated cable routed through the area. This task required the development of a cable routing database that took cable routing information and mapped it according to fire compartment.

Using this database, the plant effect of a fire in each fire compartment was determined (fire area functional consequence equated to IPE impact). Based on plant walkdown, the frequency of a fire in each fire area was determined. This calculation was based on the amount of fixed and transient combustible in each area. This probability was multiplies by a conditional core damage frequency that was calculated from the IPE using the above-determined fire area functional consequence. IF this value was less than 1E-6 per year and shown to be qualitatively conservative, the area was screened. For areas that did not screen, a more detailed analysis was performed.

The detailed analysis considered the location of ignition sources, combustibles, and targets (critical components) in the area, and fire detection and suppression capabilities. This information was used in that above-mentioned PRA calculation to perform a more detailed assessment of individual fire area core damage.

More detailed discussion of the fire IPEEE approach is located in Section 4.

2.3.2 Seismic Methodology Overview

NMPC performed a SMA for the seismic portion of the IPEEE. However, as noted above, NMPC also performed a seismic PRA based ont he results of the SMA.

The basis of the SMA is to demonstrate survivability of a set of equipment necessary to reach and maintain a safety shutdown following a given magnitude earthquake. Success paths and structures, Systems and Components (SSCs) necessary to support plant success following an earthquake are identified. Survivability must be demonstrated for 72 hours. .Those components required to mitigate a small break LOCA (SLOCA) during a review level earthquake (RLE) are considered. An RLE is the specified earthquake magnitude set by NRC in GL 88-20.

The SMA analysis can be broken into six phases. These phases are as follows:

1. Preparatory Assessment
2. SSC Identification
3. Seismic Capability Walkdown
4. Review Walkdown
5. SMA Evaluation
6. Documentation

Phase 1: Preparatory Assessment

The first step in Phase 1 is to become familiar with the SMA techniques. Analysts review appropriate methodology reports, communicate with the two EPRI demonstration plants, and receive training as appropriate.

The second step is to review important plant functions and identify SMA scope system including support systems. From these systems, at least two safe shutdown paths are selected. These paths are documented as success paths using a Success Path logic diagram (SPLD).

Phase 2: SSC Identification

Based on the safe shutdown paths,. an equipment list is generated that includes the equipment necessary to maintain the success path. This list becomes the basis for equipment that will require walkdown and analysis. A separate list that includes only SMA scope relays is developed to be specifically used in the relay chatter evaluation.

This identification is based on IPE modeling and includes a limited number of walkdowns to confirm success path logic. Walkdowns involve the IPEEE Team making observations and collecting information during tours of the plant. The next step is to perform the seismic capability walkdowns.

Phase 3: Seismic Capability Walkdown

The main purpose of the seismic capability walkdown are to:

1. Screen components that can be shown to have seismic capability above the RLE
2. Clearly define failure modes
3. Perform preliminary vulnerability assessments

The seismic capability is measured by the High Confidence/Low Probability of Failure (HCLPF) measure. Complete fragilities are developed during this task. These are used for the seismic PRA performed as additional NMP2 IPEEE scope work.

Phase 4: Review Walkdowns

Review walkdowns are performed to investigate additional success paths, collect additional information, or verify pervious analysis. These walkdowns are conducted on a case-by-case basis.

Phase 5: SMA Evaluation

Based on the walkdowns, a substantially reduced list of review elements remains for detailed review. For each review element it is necessary to perform a demand and capacity evaluation. The demand evaluation determines the level of motion expected at the component and includes the magnification of the earthquake at upper elevations of the plant. The capacity evaluation determines the ability of components to withstand an earthquake. The demand estimates can be determined either using a scaling approach or by performing new, less conservative, building response analyses.

This demand is then compared to the seismic qualification rating. Components that do not meet comparison limits can have less conservative demand evaluations performed.

Phase 6: Documentation

All calculations, assumptions, walkdowns, and analyses are documented according to the direction in the SMA methodology report. These Tier-II reports re the basis for the NRC submittal, Tier-I. Tier II reports, as specified in NUREG-1407, contain background information retained at NMPC. This report represents the Tier I information which is submitted to the NRC to describe the overall evaluation and results.

2.3.3 Others Analysis Overview

High winds, floods, and transportation and nearby facility accidents are handled using the screening approach outlined in NUREG-1407[3]. This shows a progressive screening approach based on probability and consequences. This screening starts with a review of the USAR and licensing basis and includes a review of changes made since the issuance of the operating license.

Screening and walkdowns begin on a case by case basis starting with the 1975 Standard Review plan (SRP) criteria[7]. For cases where the SRP criteria are not met, a probabilistic evaluation is made. If frequency of occurrence is less than $1x10^{-5}$ and conditional core damage is less than 0.1, then the issue can be screened. If the issue is not screened, then a more formal PRA evaluation is needed. This is based on the IPE[1] and direction given in NUREG CR-2300.[4] If contribution to core damage frequency is less than $1x10^{-6}$ then the issue is screened. Cost-benefit based on core damage frequency reduction can be used to determine specific corrections for issues that are not screened by the PRA evaluation.

2.4 Information Assembly

The principle plant information source for the NMP2 IPEEE was the NMP2 USAR[6]. This document presents a very good description of the plant design relative to external events and was last updated in April 1994. A number of other plant documents were used including: drawings, calculations, procedures, and plant operational records. These are referenced, where appropriate, throughout the Tier I and Tier II IPEEE reports.

This report comprises the Tier I documentation. Tier II documents are classified as those NMP2 IPEEE related documents retained at NMPC as reference to the information in the Tier I document. The Tier II documents include: walkdown notes, computer databases, computer models, calculations, and reports.

The IPEEE represents a "snapshot" of plant risk due to external events. Efforts made to make this analysis representative of current design and operation include:

- Using recently update USAR information

- Using most recent version of drawings, calculations, procedures, etc. to supplement USAR information
- Performing plant walkdowns to verify collected information and collect data on the current plant configuration and operation.

Walkdowns were performed for seismic, fire, and other analyses. Multiple walkdowns for each type of analysis were performed by a multidisciplined team comprised of NMPC staff and contractors. Details of the walkdown and specific team composition are presented in the discussion of each analysis (Sections 3, 4, and 5).

3.0 Seismic Analysis

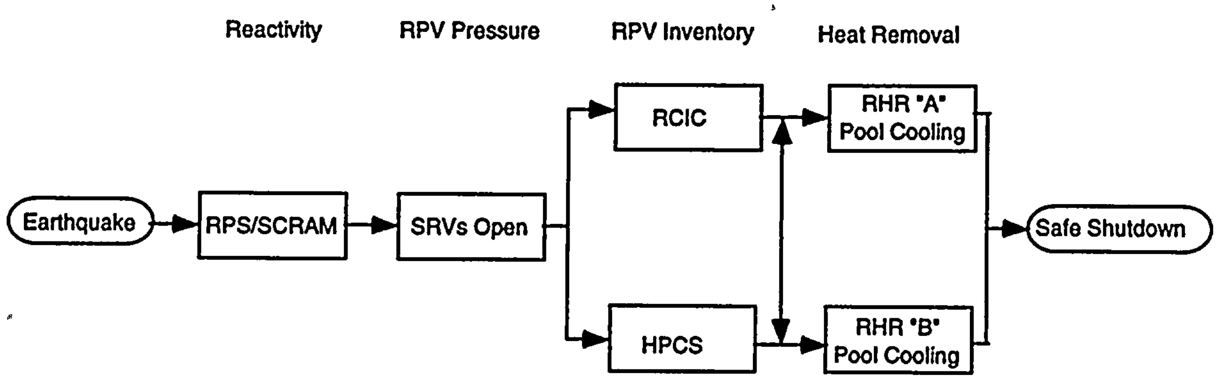
In response to Generic Letter 88-20, Supplement 4[2], NMPC committed to the EPRI seismic margins (SMA) method[11]. Understanding the importance of the IPE[1] in support of decision making and that the IPEEE should add to the completeness of the IPE, NMPC went beyond NRC guidance. The review level earthquake (RLE) used for screening was 0.5g, rather than 0.3g, as recommended by NUREG-1407[3]. The seismic capacity of NMP2 was expected to be high; utilizing a 0.5g RLE would provide more knowledge relative to the seismic capability of the plant. All relays that could impact the success path due to chatter were identified and evaluated rather than attempting to identify only those most susceptible to failure. In addition, a seismic PRA was performed to place the seismic margins analysis results into quantitative perspective and support future risk management applications. These scope increases had a minor impact on cost while providing a valuable tool for the future.

The SMA is documented in Sections 3.1. The seismic PRA is documented in Section 3.2 and references the SMA analysis to avoid repetition.

3.1 Seismic Margins Method

The NMP2 IPE[1] and industry seismic probabilistic risk assessments were used to support development of success paths and the identification of components. The seismic capability screening and analysis of components and structures, including walkdown notes, are documented in NMP2 Screening Evaluation Work Sheets (SEWS)[10].

The results of the analysis demonstrate a 0.5g or greater plant HCLPF (high confidence low probability of failure) with sufficient redundancy and reliability to assure low seismic risks.



The simplified 0.5g success path is shown in the above figure. Other success paths were also considered as described in Section 3.1.2.

The following provides a brief description of the approach and tasks associated with this analysis:

1. Functional success paths and then progressively more detailed success paths considering frontline and support systems were defined. The components required to support these systems as well as the structures that house these components were identified. Section 3.1.2 describes this analysis, including consideration of nonseismic, human actions, dependencies, and relay chatter. The components and structures identified were included in the seismic capability analysis (item 3 below) and walkdown (item 4 below).

2. Containment performance (Section 3.1.5) and other seismic interactions or issues (Section 3.3) were also evaluated to ensure that the equipment list was complete for the seismic capability analysis.

3. Structures, systems, and components identified above were reviewed for seismic capabilities including seismic qualification, analysis and test information that would support screening. Calculations were performed as necessary to support screening. Sections 3.1.3 and 3.1.4 discusses this analysis and capabilities of structures and components. This analysis was conducted prior to and subsequent to the walkdown.

4. A seismic walkdown was conducted to support the seismic capability analysis as described in Section 3.1.1.

3.1.1 Review of Plant Information, Screening, and Walkdown

A significant amount of plant information was reviewed and used in the analysis. This includes the USAR[6], NMP2 IPE[1], and numerous other documents such as drawings, procedures, seismic analysis, and seismic test reports. These additional documents are referenced in the NMP2 seismic tier 2 documents[8,9,10] .

The NMP2 site exhibits very low seismicity, but a conservative Regulatory Guide 1.60 safe shutdown earthquake (SSE) with a 0.15g peak ground acceleration was adopted as a design basis. All major safety related structures at NMP2 are founded on bedrock; therefore, liquefaction was not considered an issue for the IPEEE analysis. Section 2.5 of the USAR provides detailed information on geology, seismology, and geotechnical engineering.

The seismic capability analysis of components and structures, including walkdown notes are documented in NMP2 Screening Evaluation Work Sheets (SEWS)[10]. The SEWS are similar to those developed by the seismic qualification utility group (SQUG)[11, 12]. Examples are provided in Sections 3.1.3 and 3.1.4.

The Seismic Review Team (SRT) included the following individuals who performed a seismic walkdown, reviewed the SEWS, and are SQUG trained and certified:

Francis Feng - Niagara Mohawk Power Corp
Carman Agosta - Niagara Mohawk Power Corp
Walter Djordjevic - Stevenson & Associates
Tsiming Tseng - Stevenson & Associates

The seismic walkdown was performed on November 5-8, 1993 and is documented in the SEWS in accordance with EPRI NP-6041[11]. The following individuals also supported the SRT walkdown:

Joseph Cushman - Niagara Mohawk Power Corp
* Robert Kirchner - Niagara Mohawk Power Corp
Marvin Fetterman - Vectra Technologies, Inc.
* Thomas Casey - J H Moody Consulting, Inc.
* James Moody - J H Moody Consulting, Inc.

* These individuals participated in almost all aspects of IPE and IPEEE development at NMP2, including seismic IPEEE evaluations & walkdowns and fire IPEEE evaluations & walkdowns. They provided the coordination of these analyses and between external event teams.

Prior to the walkdown, fire water and deluge valves were identified as potential flood hazards (see Sections 3.1.2.1.5 and 4.8) and were considered by the SRT during the walkdown. No seismic fire events were identified for SRT evaluation (see Section 4.8)

The following summarizes major observations and insights from the seismic walkdown that impacted the 0.5g HCLPF screening criteria:

- The fire water header in the control building corridor on elevation 261 was judged to require additional evaluation to determine its fragility or to justify a 0.5g HCLPF. Another option was to provide additional support to the header such that deluge valve trim piping does not crush against the wall causing flooding. Further evaluation concluded a design change was not necessary and a HCLPF of 0.5g.

- It was decided that walking down all the nitrogen (instrument air) piping to confirm that it will survive at 0.5g HCLPF would be difficult. This led to dropping containment venting from the 0.5g HCLPF success path. The SMA was not impacted because there are still two redundant success paths. The significance of this can be determined from the seismic risk assessment in Section 3.2.

- High pressure nitrogen tanks, located outside, were determined to require additional analysis because of the potential for nearby vertical tanks falling onto the high pressure nitrogen tanks. Also, it was acknowledged that procedures to align this high pressure source to safety relief valves (SRVs) in the long term should include isolating nonsafety supplies to the reactor building in case of pipe leakage in these other paths. This nitrogen supply to the SRVs assured that SRVs would stay open for 72 hours to maintain low pressure injection.

  Additional analysis indicated the nitrogen tanks had a HCLPF of 0.23g. Because of this, the low pressure injection success path was subsequently dropped from the 0.5g HCLPF success path and procedure changes were not pursued. The SMA was not impacted because there are still two redundant success paths. This is discussed further in Section 3.1.2 and the risk significance of the 0.23g HCLPF can be determined from Section 3.2.

- A question was raised whether a trolley over an emergency switchgear should be better secured. After further analysis and review this was determined to be unnecessary.

- A recommendation to secure a storage rack near a RCIC motor operated valve was implemented.

- A question was raised whether instrument lines & cages should be secured from rattling because the rattling appeared to be a potential plant transient concern. There was no concern with the seismic safe shutdown path.

No weaknesses were identified with anchorage of safety related equipment during the walkdown.

3.1.2 Systems Analysis

Section 3.1.2.1 describes development of the success path and the identification of structures, systems and components within the success path. The relay chatter evaluation portion of the analysis is described in Section 3.1.2.2.

3.1.2.1 Identification of Structures, Systems & Components[8]

This section documents the evaluations conducted to identify structures, systems and components to be included in the seismic capability screening and analysis. The EPRI methodology[11] was used as guidance along with previous seismic probabilistic risk assessments (PRA) and the NMP2 IPE[1]. The end product from the evaluation includes the following:

- A functional success logic diagram, Figure 3.1-1, which identifies systems required for each safe shutdown success path, given a seismic initiating event.
- A list of structures, systems, and components and their locations, Tables 3.1-1A and 1B, identified for further seismic capability screening and analysis.

The active components identified in Table 3.1-1B are in a database that allows components to be sorted by system, component type or class, location, and cabinet. This allowed grouping of components for the seismic screening and walkdown. The "Bldg" column in Table 3.1-1B provides the component location which is further defined in Table 3.1-1A Note 1. In addition, the system designation used in Table 3.1-1B ("System" column) is identified in the functional success diagram, Figure 3.1-1.

The identification of success paths and components is based on minimal credit for operator actions. This ensures that the identification of components starts out conservatively. During the seismic capability screening and evaluation, conservatism with regard to not taking credit for operator recovering equipment failures will be reconsidered, as appropriate. The success diagram applies to both transient and small LOCA initiating events since the success criteria is essentially the same for both initiators. Thus, there is no need to consume resources evaluating components inside containment with the intent of justifying a low probability for small LOCA. In addition, the equipment list includes a minimal set of instruments required for the operators to maintain inventory control and heat removal functions. Finally, success is defined as maintaining at least hot shutdown conditions for 72 hours.

Relays and contactors that must function in order for success diagram systems to actuate are included in the equipment list developed here. Relay or contactor chatter which could prevent system operation or cause other consequential impacts are identified in Section 3.1.2.2.

As shown in Figure 3.1-1, there are several redundant systems that can provide inventory control and heat removal. This would appear good from a reliability point of view but a possible problem with regard to managing the seismic capability analysis scope. However, the LPCS and RHR systems (LPCI "C" and suppression pool cooling "A" and "B") are all judged to be very similar, if not identical, with regard to the seismic capability analysis. The equipment appears to be very similar with regard to equipment type, anchorage, and location. Thus, the seismic capability analysis can look at one system and verify that the others are similar which reduces the analysis scope. In fact, this strategy can also be used to identify the seismic capability analysis requirements across all systems identified in this section.

The following summarizes the approach utilized in this evaluation:

- Functional success paths were developed with the aid of the IPE (PRA) event tree models. The IPE event tree logic models were directly applicable to this task and the Appendix R safe shutdown analysis was reviewed as well as operating procedures.

- Support system requirements for the above functional success paths were identified. Again, the IPE model was utilized because it documented these dependencies (including dependency tables) as well as the success logic for the frontline functions in terms of support system requirements.

- Operator actions and instrumentation & controls required to support the functional success paths and other support systems were evaluated and identified. The IPE and operating procedures were utilized.

- Based on support system dependencies, past seismic PRA experience, and IPE insights, some success paths were eliminated from further consideration. For example, all systems dependent on normal offsite AC power were excluded due to the low seismic capacity of offsite AC power.

- A list of components was developed for each system with an indication of the component location. Again, the IPE models were used initially, and then piping & instrument drawings, electrical drawings, and Appendix R safe shutdown analysis were reviewed to ensure completeness in the equipment list. The location of equipment was used to ensure that the list of structures was complete for seismic capability screening and analysis.

- The success paths and related equipment were associated with providing safe shutdown (no core damage). Containment performance was also assessed to assure that those structures, systems, and components essential to maintaining primary containment integrity, including interfacing LOCA scenarios, were considered. This is described in Section 3.1.5.

- Seismic spatial systems interactions were considered to prepare for the walkdowns and to address their potential influence on seismic risk.

- The potential influence on risk of nonseismic failures and human actions was considered.

3.1.2.1.1 Identification of Functions & Frontline Systems

First, a simplified functional success diagram was developed based on satisfying those safety functions necessary to assure a safe stable shutdown condition. Consistent with the IPE, the following functions must be satisfied:

- Reactivity Control
- RPV Pressure Control
- RPV Inventory Control
- Heat Removal (Containment Pressure Control)

The simplified functional success diagram in Figure 3.1-2 was developed assuming a transient or small LOCA occurs due to the earthquake. The success criteria for transient and small LOCA initiating events in the NMP2 IPE are the same except vapor suppression is required in response to small LOCA initiators. Medium and large LOCAs were not considered because the seismic capability of piping and reactor coolant pressure boundary components is very high based on past seismic analyses. Thus, the likelihood of medium or large LOCAs is assumed to be small. This was verified in the seismic capability screening and analysis. Also, the success criteria for medium and large LOCAs requires a subset of the systems in Figure 3.1-1. Therefore, the functional success diagram is not incomplete for these initiators.

For each of the functions listed above, potential system level success paths were defined from the IPE. Then, the basis for eliminating certain systems was documented based on initial seismic capability considerations. The following summarizes the results of this evaluation with the initially selected success paths for each function "underlined". The simplified functional success diagram in Figure 3.1-2 displays the results of this evaluation:

Reactivity Control

1. <u>Reactor protection system and SCRAM function</u>

2. Given that the electrical portion of the SCRAM function fails, recirculation pump trip, alternate rod insertion and the redundant reactivity control system provide an alternate success path.

3. Given that the mechanical portion of the SCRAM function fails (or electrical portion and alternate rod insertion fails), standby liquid control, recirculation pump trip,

alternate rod insertion, feedwater trip, and the redundant reactivity control system provide an alternate success.

Although standby liquid control and the other systems in items 2 and 3 are automatic, operator actions are somewhat more demanding than a transient or small LOCA with SCRAM success. Also, the design of the RPS is fail-safe and is expected to have a high seismic capacity. For these reasons items 2 and 3 were not considered for further evaluation.

RPV Pressure Control

1. Main Condenser

2. Safety Relief Valves

The main condenser and its support systems depend on normal offsite AC power. Since the seismic capability of offsite power is known to be low, the main condenser was not considered for further evaluation. There are 18 safety relief valves and their seismic capability to open on demand is very high from past seismic PRAs. This is verified in the seismic capability screening and analysis.

RPV Inventory Control

1. Condensate & Feedwater

2. RCIC

3. High Pressure Core Spray

4. RPV Depressurization & Low Pressure Core Spray

5. RPV Depressurization & RHR C in LPCI Mode

6. RPV Depressurization & RHR A in LPCI Mode

7. RPV Depressurization & RHR B in LPCI Mode

8. RPV Depressurization & Service Water Crosstie to LPCI B

9. RPV Depressurization & Fire Water Crosstie to LPCI A or B

Condensate & feedwater (item 1) depend on normal offsite AC power. Since the seismic capability of offsite power is known to be low, condensate & feedwater was not considered for further evaluation. Items 8 and 9 were not considered for further evaluation because they both depend on LPCI A or B injection paths (items 6 and 7), fire water is not expected to have as high a seismic capacity as LPCI, service water is already included as a support system as described later, and additional operator actions are required.

Retaining items 2 through 7 would appear to be an excessive number of success paths. However, there is symmetry between items 4 through 7. LPCS and RHR A are located in the North auxiliary bay. RHR B and C are located in the South auxiliary bay. These auxiliary bay structures and the anchorage and design of all four systems are very similar. Therefore, these systems can be considered one system for seismic capability analysis purposes. In addition, RHR A and B must be retained because these systems, in the suppression pool cooling mode, also satisfy the containment heat removal function described below.

Heat Removal (Containment Pressure Control)

1. Main Condenser

2. <u>RHR A in Suppression Pool Cooling</u>

3. <u>RHR B in Suppression Pool Cooling</u>

4. <u>Containment Venting</u>

5. <u>Vapor Suppression</u>

As described above under RPV pressure control, the main condenser and its support systems depend on normal offsite AC power. Since the seismic capability of offsite power is known to be low, the main condenser was not considered for further evaluation. The suppression pool cooling and LPCI modes are shared within RHR A and B as described under RPV inventory control. Therefore, these systems can be considered as one system for seismic capability analysis purposes. The shutdown cooling mode of RHR is not explicitly identified above because it shares much of the same equipment already included in the suppression pool cooling systems. Operator actions are required from the control room to align RHR in the heat removal mode.

Containment venting is a hardened system and was considered because of the limited additional equipment required to include the system for completeness. Long term local operator actions are required to align the hardened vent. Although this system is shown in the success diagrams, during the walkdown, the seismic review team decided to remove the containment venting success path for the following reasons:

- The nitrogen supply outside primary containment is not safety related and it would be difficult to walkdown all the many small lines that could leak during a seismic event and fail the nitrogen supply to the purge valve inside containment.

- Eliminating containment venting does not significantly impact the reliability of the containment heat removal function. Support systems required for RHR are also required for other functions in the success path and must be available. The RHR system is expected to have a high seismic capacity.

The vapor suppression function is assumed to be required in the short term to support primary containment control during small LOCA scenarios. Although the operators have at least 30 minutes to mitigate vapor suppression failure for a small LOCA, these actions are neglected.

3.1.2.1.2 Identification of Support Systems

Systems required to support the frontline systems defined in the previous section (Figure 3.1-2) were identified from the IPE (detailed dependency tables) and checked by reviewing the USAR, operating procedures, and drawings. This evaluation assumes that reactivity control, RPV pressure control and RPV inventory control must initially function automatically without the operator. Long term operator control and recovery actions are assumed to be required and are allowed. Long term heat removal is not automatic and requires operator action. Instrumentation requirements to support RPV inventory control and heat removal are identified later in this section.

The dependencies for each frontline system are described below. The results of this evaluation are shown in Figure 3.1-1. Figure 3.1-2 is similar except support systems have been added to the logic as described in this section.

Reactor protection system and SCRAM function
The reactor protection system input signals de-energize to actuate. Therefore, the input signals are fail-safe upon loss of 120V AC power. The scram signal will cause electrical power to be interrupted to the scram pilot solenoid valves for each CRD hydraulic control unit, causing the solenoid valves to vent nitrogen allowing all the control rods to be rapidly inserted into the reactor core. The scram pilot solenoid valves fail-safe upon loss of their support systems (instrument air and power). No additional systems were added to the functional success diagram to support the reactivity control function.

Safety Relief Valves
There are 18 SRVs which depend on 125V DC power and nitrogen gas to respond in the relief mode. However, operation in the safety mode (SRV spring only) does not depend on these support systems. RCIC and HPCS are capable of providing RPV makeup at the safety valve setpoint (at least, at the two lowest pressure settings). For these reasons, no additional systems were added to the functional success diagram to support the initial RPV pressure control function. Seven of the 18 SRVs are also utilized with the automatic depressurization system (ADS) which is described below with the RPV inventory control systems.

RCIC
RCIC operation depends on Division I 125V DC power, the ECCS initiation system, and

120V AC uninteruptable (UPS) power. ECCS initiation depends on Divisional DC power and UPS power. RCIC initially takes suction from condensate storage tank (CST) "A" and switches to the suppression pool on low CST level. The success criteria for safe shutdown is 72 hours and the capacity of the CST tanks are not adequate to meet this criteria. The CST is not required for success and its failure will not impact transfer to the suppression pool because the reference leg instrument line and instruments are in the pipe tunnel, not next to the tanks. Also, long term success of RCIC will require room cooling which requires Divisional AC power and service water or the operators to prevent high temperature RCIC trips. Room cooling equipment and its dependencies were included in the initial evaluation.

<u>High Pressure Core Spray (Division III)</u>

HPCS is almost a totally independent system and is referred to as Division III. It has its own dedicated diesel, AC power supplies, 125V DC power, 120V AC, automatic actuation, and instrumentation. When offsite power is available, the only support dependency is service water for room cooling. The HPCS diesel also depends on service water when offsite power is unavailable. Offsite power is assumed unavailable (due to low seismic capability) which means that the HPCS diesel is required as well as service water. Since service water depends on Division I and II AC power, HPCS becomes dependent on Division I and II AC power. Also, Division I and II AC power depends on Division I and II DC power to start emergency diesels and service water pumps. Therefore, HPCS dependencies must include these Division I and II dependencies for success during an earthquake. HPCS initially takes suction from condensate storage tank "B" and switches to the suppression pool on low CST level or high suppression pool level. The success criteria for safe shutdown is 72 hours and the capacity of the CST tanks are not adequate to meet this criteria. The CST is not required for success and its failure will not impact transfer to the suppression pool because the reference leg instrument line and instruments are in the pipe tunnel, not next to the tanks.

<u>RPV Depressurization (ADS)</u>

The automatic depressurization system (ADS) is required when the high pressure injection systems (RCIC and HPCS) fail and injection from the low pressure systems are required. ADS depends on Divisional 125V DC and nitrogen gas for safety relief valve (SRV) operation and the ECCS initiation system for automatic opening. ECCS initiation depends on Divisional DC power and UPS power. In the long term, Divisional AC power is required for the operators to align nitrogen tanks from outside containment to keep the SRVs open. Since AC power requires emergency diesels for success, service water is required for diesel cooling and becomes a dependency for long term ADS success. The dependency on nitrogen must consider availability for 72 hours versus 24 hours in the IPE. For this reason, the high pressure nitrogen bottle supply which was not required in the IPE may be required for the 72 hour duration. On the other hand, aligning RHR to the shutdown cooling mode could be an alternative to requiring high pressure nitrogen for the long term.

<u>Low Pressure Core Spray</u>

LPCS depends on Division I AC power, DC power, UPS 120V AC, and ECCS initiation systems as well as room cooling which depends on Division I AC power and service water.

The operators can recover loss of room cooling by opening doors. ECCS initiation depends on Divisional DC power and UPS power.

Low Pressure Coolant Injection C

LPCI "C" depends on Division II AC power, DC power, UPS 120V AC, and ECCS initiation systems as well as room cooling, which depends on Division II AC power and service water. The operators can recover loss of room cooling by opening doors. ECCS initiation depends on Divisional DC power and UPS power.

RHR A in LPCI Mode

LPCI "A" has the same dependencies as LPCS and since the suppression pool cooling and LPCI functions are shared with this system, it is discussed below under Suppression Pool Cooling "A".

RHR B in LPCI Mode

LPCI "B" has the same dependencies as LPCI "C" and since the suppression pool cooling and LPCI functions are shared with this system, it is discussed below under Suppression Pool Cooling "B".

RHR A in Suppression Pool Cooling

This system depends on Division I AC power, DC power, and service water to the heat exchanger. Also, room cooling is required which depends on Division I AC power and service water. The operators can recover room cooling by opening doors, but service water is still required for suppression pool cooling. Note that suppression pool cooling does not depend on UPS 120V AC power and ECCS initiation, but LPCI does in order to open the motor operated injection valve.

RHR B in Suppression Pool Cooling

This system depends on Division II AC power, DC power, and service water to the heat exchanger. Also, room cooling is required which depends on Division II AC power and service water. The operators can recover room cooling by opening doors, but service water is still required for suppression pool cooling. Note that suppression pool cooling does not depend on UPS 120V AC power and ECCS initiation, but LPCI does in order to open the motor operated injection valve.

Containment Venting

Containment venting depends on Divisional AC power and either nitrogen or instrument air. Since the instrument air system depends on normal offsite AC power which has a low seismic capability, instrument air was not considered for further evaluation. Since Divisional AC power depends on emergency diesels which in turn depend on Divisional DC power and service water, these become dependencies for containment venting. Operator action to align containment venting should be considered reliable because it is not required immediately after a plant trip. The dependency on nitrogen must consider availability for 72 hours versus 24 hours in the IPE.

As described previously, demonstrating the seismic capability of multiple nitrogen supply lines would be difficult and the RHR system has redundancy and is seismically capable. Thus, the containment venting success path was dropped from further consideration during the seismic walkdown.

Vapor Suppression
The suppression chamber to drywell vacuum relief valves have to be functional, but there are no support system dependencies.

Instrumentation
Besides the instrumentation required to support actuation of the above systems, instrumentation is required for the operators to maintain inventory control and heat removal functions. These instruments and their dependencies are identified later in this section.

3.1.2.1.3 Evaluation of 72 Hour Success Criteria

The seismic evaluation requires safe shutdown conditions for 72 hours rather than the 24 hours used in the IPE. As a result, those support system dependencies in the IPE that were potentially sensitive to time were identified and evaluated. The following summarizes these considerations:

- Condensate storage tanks: These tanks are judged inadequate to last 72 hours and were not included in the model. The automatic suction transfer function from the associated CST to the suppression pool is required for RCIC and HPCS.

- Nitrogen storage: RPV depressurization (ADS) and containment venting require a long term high pressure nitrogen supply. As described above, containment venting was dropped from the success path and is not required. Also, it is possible to align RHR to shutdown cooling as a long term alternative to requiring high pressure nitrogen and ADS.

- 125V Divisional DC Power: Since Divisional AC power is required, the batteries need only survive the earthquake and be available on demand to support emergency diesel starting and other initial start loads. As long as the static charger and AC power are available after this battery demand, the batteries are not required in the long term. Note that the batteries can not supply DC loads for 72 hours without AC power support.

- Emergency Diesel Fuel Supply: The diesel fuel supply will last for 72 hours.

- Room Cooling: Unit coolers and equipment identified as important in the IPE are included in Table 3.1-1B. Those areas screened out in the IPE were reviewed to ensure that there are no new components that should be added to Table 3.1-1B. As a result of this review, components associated with RCIC, LPCS, and RHR pump room cooling were added to the equipment list.

3.1.2.1.4 Component List Development

Tables 3.1-1A and 1B represent the final list of components required to maintain the safety functions and systems identified in Figure 3.1-1 (success diagram). Table 3.1-1A includes a list of structures and passive components. Table 3.1-1B includes a list of active mechanical and electrical components. Note that manual switches, valves, check valves, and valves with actuators that do not have to change state are excluded from Table 3.1-1B. However, their pressure boundary capability must be considered along with piping in Table 3.1-1A. Instrumentation, relays, contactors, and operators required to support system actuation are included in Table 3.1-1B. Relay and contactor chatter is not included here. This evaluation is included in Section 3.1.2.2. Also, the evaluation of nonseismic failures, human actions, containment performance, and system interactions are assessed in later sections.

The success diagrams and subsequent development of the component tables were developed initially from the IPE. Table 3.1-2 identifies those IPE systems and event tree top events that are included in the success logic diagram. These event tree top events are included in the success logic diagram as shown in Figure 3.1-3. The fault trees and drawings developed for the IPE were used to identify components to include in Tables 3.1-1A and 1B. Table 3.1-2 also identifies those event tree top events from the IPE that were not included in the seismic success path. The following summarizes why these top events are not included:

- Station Blackout Top Events - the seismic success diagram does not allow station blackout recovery. This model is operator action intensive and the probability of recovering AC power after a relatively large earthquake is very uncertain and therefore, is neglected in this analysis.

- ATWS Top Events - The SCRAM function is reliable and is expected to have a high seismic capacity as the electrical portion is fail-safe. In addition, the ATWS model requires operator actions and therefore, is neglected in this analysis.

- Normal AC Power Dependent Top Events - Systems and top events that depend on normal AC power are excluded. As described in the previous sections, normal offsite AC power is known to have a low seismic capacity.

- Containment spray and LPCI "A" and "B" injection paths were not included in the success paths, but there are other identical redundant component paths already included in the success diagram.

- Level 2 top events are not included, but containment performance is considered in a later section.

- Service water and fire water crossties to RHR injection paths are not included because most of the equipment is already included and these capabilities include additional operator actions.

- The condensate storage tanks are not included since they are not required when transfer to the suppression pool is successful. Additionally, their inventory will not last 72 hours as required for seismic success criteria.

- Several operator actions are not credited, but may be considered later, if necessary.

To ensure completeness in the component lists, the following drawings and data were reviewed: system piping and instrumentation diagrams, electrical diagrams, other electrical & mechanical equipment location data, Appendix R safe shutdown analysis, USAR, and the operating procedures. The location (i.e., building) of components in the tables was identified and provided a check that all plant structures needed to support the success path had been identified.

The remainder of this section documents notes on the systems review.

<u>Scram Function</u>
In the IPE, a simplified model was used because the reactor protection system input signals are de-energize to trip and the scram inlet and outlet valves fail open on loss of support systems. If both hydraulic control unit scram valves fail to open due to the seismic event, the potential exists for common cause failure to scram (i.e., CRD pumps are assumed to be lost and accumulators leak and depressurize). Thus, these valves are included in Table 3.1-1B (2RDS*AOV126 and 127 are added as typical of 185 CRDs). Mechanical failure of reactor internals, CRD housing & supports is included in Table 3.1-1A.

If offsite power is available and/or other support systems are available during a seismic event, fail-safe signals can not be assumed. In this case, the input signal failure mode would have to prevent all signal parameters in at least two scram channels from providing a scram signal. Several diverse input signals would have to fail and no spurious signals from the earthquake could occur. This is considered very unlikely and is not modeled in the success diagram.

<u>Pressure Relief</u>
There are 18 safety relief valves and their seismic capability to open on demand in the safety spring mode of operation does not depend on support systems. The spring safety function associated with these valves is included in Table 3.1-1A. The automatic depressurization function is described later.

<u>Instrumentation Requirements</u>
The instrumentation needed to respond to a transient caused by a seismic event should include those instruments used to start and run the selected frontline systems, their support systems, and perform the expected EOP directed actions. The instruments required to start and run

systems in the success diagram are identified for each system.

A minimum set of instrumentation was identified for the operators to maintain inventory control and heat removal functions. The NMP2 IPE and EOPs were used to define the equipment. The parameters most important and chosen for seismic capability screening analysis include reactor vessel level and pressure, suppression pool level and temperature, and drywell pressure and temperature. The applicable components, power supplies, and locations are included in Table 3.1-1B.

Other parameters such as suppression chamber pressure and temperature, hydrogen and oxygen concentrations, and radiation levels were considered less important and were not evaluated. In addition, the support system requirements, component types and locations are very similar to the parameters chosen.

One potential systems interaction concern has to do with the possibility that failure of some instrumentation could lead the operator to perform undesired actions. For example, failure of several rod position indicators and failure of APRMs could force the operator to consider liquid poison and power control via reduced RPV water level. Therefore, APRMs and its indicating device are included in Table 3.1-1B.

Vapor Suppression

Vapor suppression function initial success requires integrity of the downcomer pipes, drywell floor, and the vacuum breaker check valves (2ISC*RV33A, 33B, 34A, 34B, 35A, and 35B) must stay closed. Thus, these components are included in Table 3.1-1A. The safety relief valve (SRV) vacuum breakers are not included because vapor suppression failure requires a stuck open SRV and a failed open SRV vacuum breaker path and a failed open downcomer vacuum breaker path.

Room Cooling

In the IPE, room cooling was assessed to be important and was modeled in the following areas:

- Emergency diesel cooling (Div I, II and III)
- HPCS pump room
- RCIC pump room only because of high temperature trips. There is significant time for operators to disable high temperature trips.
- North and South Auxiliary Bays (Room Cooling): The low pressure core spray and RHR pump rooms and their associated motor control center (MCC) rooms are located in these buildings. The pump rooms are most important, but operators can open doors to mitigate loss of cooling. The MCC rooms are not as important because it takes several hours to heatup to failure temperatures. If the necessary equipment is started

and running prior to this time, there is no impact.

Unit coolers and equipment necessary to support the above are included in Table 3.1-1B. No operator recovery is presently included.

<u>RCIC</u>
In the IPE, RCIC transfer to the suppression pool was not modeled because RCIC could provide inventory control from the condensate storage tanks (CSTs) for 24 hours. Since the CSTs are not included in the success diagram and 72 hours are required for success, components required for RCIC transfer to the suppression pool are included in Table 3.1-1B. CST failure will not impact transfer to the suppression pool because the reference leg instrument line and instruments are in the pipe tunnel, not next to the tanks. However, even if transfer failure occurred, the operators can manually transfer suction to the suppression pool from the control room. If RCIC trips on low pump suction pressure, it can be restarted from the control room after the suppression pool suction MOV has been opened.

Mechanical overspeed trip of the Terry turbine is not modeled in the IPE. Seismic vibratory motion could cause a trip that must be reset locally. If the shake was strong enough, then damage may occur to the latching portion of the trip mechanism. In this case, reset may not be possible. These failure modes were considered by the seismic review team during the walkdown.

Seismically induced failure of the instrument line for the pump suction pressure will cause RCIC pump trip which can not be reset or recovered. The same is true for any 1 of 4 high steamline flow/instrument line break detectors. These were considered during the walkdown.

For the low steamline pressure detectors, failure of two lines is required to cause nonrecoverable failure of RCIC.

RCIC pump, governor actuator, lube oil cooler and lube oil lines were inspected during the walkdown.

Relays required for system actuation and components required to support room cooling are included in Table 3.1-1B.

It appears that RCIC trips due to relay chatter are recoverable from the control room. However, this is considered further in the relay chatter evaluation.

<u>HPCS</u>
CST failure will not impact auto transfer to the suppression pool. However, as described above for RCIC, a failure to transfer suction paths is recoverable from the control room.

An instrument line failure (low flow or low pressure instrument line) can result in failure of the minimum flow actuation. This can result in a nonrecoverable pump failure. These lines were inspected during the walkdown.

The diesel engine, generator, and controls were treated as a simplified model in the IPE. These specific components have been identified in Table 3.1-1B. Vendor supplied components such as engine control circuits and generator field flash and exciter circuits were field inspected during the walkdown and added to Table 3.1-1B.

Components required to support HPCS pump room and emergency diesel room cooling are included in Table 3.1-1B.

Generator switchgear has lockout relays that cannot be reset from the control room. This is considered in the relay chatter evaluation.

All MOVs except throttling type have seal-in control circuits. These are considered further in the relay chatter evaluation.

<u>LPCS & LPCI</u>
The sensing lines for the injection motor operated valve, if severed, will prevent this valve from opening. These lines were inspected during the walkdown.

Components include those identified in the IPE and relays required for system actuation are included in Table 3.1-1B.

<u>ADS</u>
The IPE did not model automatic ADS actuation because it was conservative to assume that the operators initially inhibited ADS and then manually initiated ADS when RPV water level reached top of active fuel. The necessary components for automatic initiation were identified and are included in Table 3.1-1B.

Each ADS valve can be opened by actuation of any one of its three solenoids (two of three solenoids are Divisional safety related). The ADS actuation signal is generated when two seal-in relays are sealed in, either by chatter of the two seal-in relays or some combination of chatter in the signal and seal-in relays. If the seal-in relays chatter, then the ADS valves open without the time delay or without the LPCI pump flow permissive being satisfied. This is considered in the relay chatter evaluation.

<u>RHR Suppression Pool Cooling "A" and "B"</u>
Components include those identified in the IPE. Operator action is required to align the RHR heat exchangers and open the return path to the suppression pool.

The shutdown cooling mode of RHR was not included in the success diagram because many of the same RHR components are already included in the suppression pool cooling mode of operation. However, this mode of operation could be utilized to maintain both low RPV pressure for inventory makeup and heat removal when high pressure nitrogen is unavailable to support ADS (e.g., to keep SRVs open beyond 24 hours to support low pressure inventory makeup). Thus, the components required to support shutdown cooling are identified here for completeness.

Shutdown cooling is different from suppression pool cooling in that suction is from the reactor coolant system rather than the suppression pool and discharge is to the reactor coolant system rather than the suppression pool. The shutdown cooling suction and return valves can not open if reactor pressure is greater than 128 psig. With one shutdown cooling loop in operation, reactor coolant can be cooled to 212F within 20 hours after rod insertion. The reactor is initially cooled and depressurized using the solenoid actuated safety relief valves.

Utilizing shutdown cooling requires that an isolation valve in each reactor recirculation loop be closed to force return flow through the jet pumps and into the core. Because these valves are powered by 2NHS-MCC011 and MCC012, which are supplied from offsite power, they are not expected to be operable after a seismic event. However, these MCCs can be fed from a diesel generator via a cross feed arrangement. Shutdown cooling is not needed within the first 24 hours, therefore, there is ample time for operator action to realign the electrical buses. In addition, aligning shutdown cooling without isolating valves in the reactor recirculation loops may provide acceptable heat removal (must maintain pressure below 128 psig). Analysis that demonstrates that natural circulation between the RPV and the cooled recirculation loop can maintain pressure below 128 psig would be required.

In addition to those components included in the suppression pool cooling function, the following major components are not included in Table 3.1-1B, but would be required to support the shutdown cooling function:

- 2RHS*MOV112 & 113, common suction from recirc loop A
- 2RHS*MOV2A & 2B, pump 1A & 1B suction MOV, respectively
- 2RHS*MOV1A & 1B, suppression pool suction MOVs
- 2RHS*MOV40A & 40B, return to recirc loops A & B
- 2RHS*FT14A & 14B (2CES*RAK018 & 021), RHR flow rate
- 2SWP*FT13A & 13B (2CES*RAK018 & 021), SWP flow rate
- 2RHS*TR190 (2CEC*PNL601), temperature recorder
- 2RHS*TE13A & 13B (2VBS-PNLB101), local temperature elements that depend on normal AC power, but can be aligned to emergency diesel supplied power, if necessary.

- 2RCS*MOV10A, 10B, 18A & 18B, recirculation pump isolation valves, and associated non safety related power supplies, 2NHS-MCC011 and 012. These may not be required if natural circulation is shown by analysis to be acceptable.

High Pressure Nitrogen
Components include those identified in the IPE. Local operator action is required to align the high pressure nitrogen for long term ADS and for containment venting. The nitrogen system piping and components are not safety related except those portions that interface with ADS and containment isolation. There is a lot of piping associated with supporting the containment venting supply path and the slightest leak would probably prevent the 72 hour success criteria from being met. For this reason and the fact that RHR provides redundant success paths for heat removal, it was decided during the walkdown to not take credit for the containment venting success path. This is discussed further in the previous sections.

The portion of high pressure nitrogen outdoors in the nitrogen area was walked down and there is limited nonsafety piping up to the ADS supply. It was noted that procedures associated with aligning the backup high pressure bottles should acknowledge that the nonsafety supply to TK2 in the reactor building should be isolated. Otherwise, the backup nitrogen bottles could be discharged through a broken line in the reactor building. Because of redundancy in the high pressure makeup function and the fact that RHR can be aligned to the shutdown cooling mode in the long term, neither the procedure change nor credit for nitrogen and low pressure injection in the long term was modeled.

Containment Venting
Components include those identified in the IPE. Local operator action is required to align the hardened vent. The suppression chamber purge vent path is included in Table 3.1-1B which includes the inside containment purge isolation valve and associated solenoid operated valves. Valves outside containment (AOVs, SOVs, and MOVs) are excluded since local manual action is already required to align the hardened vent and to open the outside AOVs. As discussed above, the containment venting success path was dropped during the seismic walkdown.

Divisional power
With regard to Divisional DC and AC power, including UPS supplies, components include those identified in the IPE. Certain other electrical areas were developed with simplified models and the additional relays, panels, and components identified for those areas are included in Table 3.1-1B.

The location of relays associated with diesels (Div I, II and III) have been identified at the panel level. Additional relays supplied by the diesel engine vendors were not identified initially as to the specific models and panels where they are located. However, these panels and relays were inspected during the walkdown and added to Table 3.1-1B.

Service Water

Components include those identified in the IPE. Relays associated with load shedding, auto start of the service water pumps, and MOV closure were added to Table 3.1-1B.

<u>ECCS Actuation</u>
Components include those identified in the IPE.

3.1.2.1.5 Spatial Seismic Systems Interactions Potential

The potential for spatial system interactions was considered as part of the seismic walkdown. System interaction issues are considered and noted on the screening and evaluation walkdown sheets. The following provides examples of what was included:

- Proximity: The proximity of structures to components and components to components was considered during the walkdown. For example, the proximity of valve operators to structures and other components was considered.

- Seismic II over I: Although this was considered in the plant design basis, it also was considered during the walkdown. Examples include consideration of instrument lines and the proximity of block walls to equipment.

  Experience at NMP2 indicates that bumping or striking instrument lines has caused spurious actuation of components such as level transmitters. This is not only a II/I potential concern, but could be a concern from the earthquake itself. This was considered during the walkdown.

- Seismic Spray & Flooding: The possibility of water spray and flooding impact on systems was considered during the walkdown. A systems evaluation of potential flooding impact on the success path is discussed further below.

With regard to flooding, the IPE was reviewed and used to assess the potential importance of internal floods caused by an earthquake. The following major flood sources were identified in the IPE:

- Systems connected to lake Ontario
  - Service Water
  - Fire Water
- Cooling tower and circulating water system
- Condensate storage tanks
- Suppression pool
- Closed loop cooling systems (RBCLC and TBCLC)

Service water supplies unit coolers, heat exchangers and equipment throughout the plant and can supply an unlimited amount of water. However, the service water system is seismically designed and nonsafety related portions of the system are isolated in the system model. Given the expected high seismic capacity of this system, the likelihood of significant flooding from service water is low. In any case, failure of service water can not be tolerated in the success diagram because there is no alternate success path.

Fire water is typically nonsafety related and considered more susceptible to seismic failure. The reactor building is very large and there would be significant time to isolate leaks before all the low pressure injection systems could be flooded in the auxiliary bays. The most sensitive and important area identified in the IPE was the diesel generator building because emergency switchgear and diesel generators are located here at elevation 261. There is a fire water header (station) on elevation 261, in the hall between the diesel and switchgear rooms. The large header piping is not expected to fail, however, deluge valve trim piping could be crushed and fail if the header impacts the wall during a seismic event. Failure of these small lines will cause deluge valves to open and flood normally dry fire water piping. This normally dry piping is connected by Victualic couplings that may also leak. This fire water header and the deluge valve trim piping were included in the scope and walked down.

The cooling tower water basin could gravity drain to the turbine building if the circulating water system pressure boundary fails during an earthquake. If offsite power is unavailable, MOVs can not be closed remotely to isolate the flood source. It is possible that the operators could locally close MOVs to isolate the flooding, depending on the leak location and its size. Even if the cooling tower basin drained into the turbine building, the resulting water level would not reach the control building and important electrical areas at elevation 261. However, the piping tunnels that interface with other buildings would be flooded. Interfaces with the reactor building were identified as most important because all the ECCS pumps are located at lower elevations from the turbine building and piping tunnels. If the building separation seals fail due to the seismic event and hydrostatic head of the water accumulating in the piping tunnel, a large fraction of the cooling tower could end up in the reactor building which could flood all ECCS pumps. For this reason, the reactor building penetration seals that interface with the turbine building through the piping tunnels were added to the equipment list for seismic capability evaluation (see Table 3.1-1A).

In November 1987, a condensate storage tank failed, leaking into the piping tunnel and then into the reactor building at NMP2. An inspection of reactor building penetration seals in 1987 found that one seal boot was damaged, probably from standing on it during installation of conduit. These seals are not required to be periodically inspected since they are not required to be fire rated. All penetration seals were inspected and the penetration area was "posted" to effectively eliminate damage by persons or objects leaning on the boot during future work done around these penetrations. These seals are QA Category I Seismic structure components and are designed for a water pressure of 28 psi.

Failure of the condensate storage tanks can also flood the reactor building through the piping tunnel if isolation water tight seals fail. If we assume the tanks fail and building seals fail, approximately 6 feet of water could collect on elevation 175 of the reactor building. This could potentially affect HPCS and/or RCIC since some valves and equipment are located in the secondary containment. However, the pumps and most of the major components are located in flood protected rooms and above the flood level. RPV depressurization equipment is located above the flood level and low pressure injection systems are located in the auxiliary bays in flood protected rooms (major components are also above the flood level). For these reasons, CST failures are assessed to be insignificant to risk. Still, as described above, the reactor building interface seals were added to the equipment list due to the potential of circulating water flooding into the turbine building and pipe tunnels.

Failure of the suppression pool or connected ECCS piping would uncover the ECCS suction lines. Since the CSTs are not included in the success diagram, failure of the suppression pool would likely lead to core damage. The suppression pool and connected piping are included in the seismic capacity assessment and are expected to have high capacities.

Flooding caused by a breach in limited volume systems, such as RBCLC and TBCLC, would have no significant impact on success path equipment.

Section 4 provides analysis of fire risk including consideration of seismic-fire interactions.

3.1.2.1.6 Nonseismic Failure and Human Action Considerations

The evaluation of seismic risk requires consideration of nonseismic failures and human actions. The following systems in the success diagram (Figure 3.1-1) have the highest nonseismic unavailabilities:

- The emergency diesels are the most important support system. The unavailability of diesel generators tend to be higher than most components and offsite power is not expected to be available due to its low seismic capacity. Seismic failure of offsite power (nonrecoverable) and nonseismic failure of the emergency diesels (recoverable) would result in a station blackout. The availability of RCIC would allow for some recovery time depending on operator actions such as shedding DC loads and disabling RCIC trips. Even with successful operator actions, the plant cannot survive for 24 hours in the IPE without AC power recovery.

- RCIC and HPCS are single train systems and have higher unavailabilities than the low pressure injection systems. Given the high availability of the ADS system and the multiple low pressure systems, it would appear that the seismic analysis should concentrate on this path in the success diagram. In other words, if the ADS and low pressure injection systems are seismically robust, there may be no need to analyze RCIC and HPCS. The similarity of LPCS and LPCI systems would also reduce the amount of work required. Also, LPCI "A" and "B" (RHR "A" and "B" systems) can provide the heat removal function (RHR heat exchangers) and share the suppression pool cooling and shutdown cooling modes of RHR. Thus, it is possible to address both low pressure injection and heat removal with the RHR systems.

However, in a seismic PRA, the availability of RCIC could be very important in assessing seismic station blackout risk (see discussion above). Thus, a strategy to neglect RCIC in the assessment because emergency diesels and low pressure injection systems have relatively high seismic capacities can not be taken for a seismic risk assessment.

The success diagram development and the identification of components is based on minimal credit for human actions (automatic actuation is included in the seismic assessment). The following operator actions are required in the success diagram:

- Nitrogen makeup to the ADS valves is required in order to keep the SRVs open in the long term. The operators have several hours, this action is proceduralized, and initial actions can be accomplished from the control room. High pressure nitrogen bottles are required to keep the SRVs open for 72 hours and eventual local action to align this system is required. Also, aligning RHR to the shutdown cooling mode of operation is a possible alternative to having to align high pressure nitrogen outside. This shutdown cooling mode of operation is presently excluded from the success diagram.

- Establishing the heat removal function requires the operators to align RHR heat exchangers in the suppression pool cooling mode from the control room. The operators have several hours, this action is proceduralized, and the actions can be accomplished from the control room. Also, aligning the shutdown cooling mode of RHR is an alternative. This shutdown cooling mode of operation is presently excluded from the success diagram.

- As a backup to aligning RHR heat removal, containment venting is shown in the success diagram. Since this system depends on normal AC power, additional local actions are required to align this system outside the primary containment. Again, there are several hours and procedures that address these actions. As explained in previous sections, containment venting was dropped from the success diagram during the seismic walkdown.

The IPE modeled an operator action to manually depressurize the RPV at top of active fuel when high pressure injection systems are unavailable. It was assumed that the operators correctly inhibited ADS per the EOPs, thus requiring this operator action to provide successful low pressure injection. If the operators correctly inhibit ADS after an earthquake, there is no reason to believe that they would not depressurize the RPV at top of active fuel per the EOPs. This assumption reinforces the importance of level instrumentation. Also, the equipment necessary to actuate ADS automatically is included in Table 3.1-1B.

Other potential operator actions that may be considered dependent on the seismic capability of components include the following:

- If the fragility of the vapor suppression function is low, the operators can mitigate this failure by initiating containment sprays, emergency depressurizing the RPV, or venting containment, if available.

- If the fragility of room cooling equipment is low, the operators have time to open doors and perform actions identified in the IPE.

- If automatic actuation of systems, including ADS, has a low fragility, manual initiation of systems will be considered.

3.1.2.1.7 Similarity & Grouping of Components

The "class" column in Table 3.1-1B is used to identify the applicable "Screening and Evaluation Sheet" in EPRI NP-6041, Appendix F that applies to the component. Classes 1 through 24 correlate to Figures F-1 through F- 24 in Appendix F. Components in Table 3.1-1B can be sorted by "class" to support walkdowns and seismic capability screening and analysis. Grouping of similar components by component type, location and cabinet can also be performed to support the seismic screening, walkdowns, and capability analysis.

3.1.2.2 Relay Chatter Evaluation[9]

This section documents the relay chatter evaluation conducted on NMP2 to assure that the potential risk from seismic events are understood at NMPC and that the requirements of Generic Letter 88-20 are satisfied. The EPRI methodology[11, 13, 14, 15, 16] was used as guidance along with previous seismic probabilistic risk assessments (PRA) and the NMP2 IPE. Development of the functional success diagram and the identification of structures, systems and components, including relays, that are required to function during the earthquake are identified in Section 3.1.2.1. This evaluation of relay chatter is based on the previously developed functional success diagram and the related systems and components that are required to support safe shutdown of the reactor after an earthquake induced transient.

A functional relay chatter evaluation was first performed to identify those relays to be included in the seismic capability screening and analysis. Table 3.1-3 summarizes the results of the relay chatter evaluation which considers the expected states of the relay prior to the earthquake and then in response to the event. The important characteristics of each relay with respect to relay chatter are included in the table as follows:

- Component Id - Identifies each relay
- System - Identifies the system from the functional success diagram
- Location - Cabinet location is provided
- Type - Type and model number where available
- Contact - Includes coil state and contact state as follows:

- Coil state, "E" for energized and "D" for deenergized
- Contact state, "O" for open and "C" for closed
- GERS - A code is used to identify the applicable GERS by referencing the page number in EPRI NP 7147-SL "Seismic Ruggedness of Relays" that describes the level of seismic demand the relay can withstand without chatter

The predominant state is a deenergized coil with open contacts (D/O) which in the transfer state becomes an energized coil with closed contacts (E/C). This relay state sequence accounts for the vast majority of relays. There are no cases of a deenergized coil and closed contacts (D/C) that remained after the functional screening process. There are a few instances of energized/open (E/O) and several energized/closed (E/C) relays.

This analysis identified 181 relays where chatter could potentially cause failure of a system in the functional success diagram. However, there is significant commonality in types, contactor states, and locations. The next step is to evaluate the seismic capacity of these relays or screen out the relays based on high seismic margins. After the seismic margin screening, if there are relays remaining with relatively low seismic margins, additional analysis may be required. For example, recoverability of relay chatter impact, including the timing and adequacy of procedures may be considered for certain relays. In addition, the risk significance may be evaluated to determine the importance of relays.

The following summarizes potential relay chatter impacts on systems and components based on this evaluation (assumes relay chatter occurs with no consideration of seismic margins):

- The predominant system impact relates to the chatter of protective relays for motor driven pumps and diesel generators. Chatter results in the tripping of these components which must be reset locally.

- Chatter of other auxiliary relays associated with ECCS actuation can result in system actuation without a real system demand. In most cases this is considered a success for the system, however, the possibility exists for ADS actuation while the diesels are locked out requiring local reset.

- With the exception of RCIC, relay chatter in valve circuits have a minor impact. A valve can change position or even cycle, but will either reposition itself or the movement will be small. In the case of RCIC, there are relays that can close the steam supply isolation valves and trip the turbine trip valve. In one case, chatter is recoverable from the control room, the other case requires local recovery.

The possibility of an interfacing systems LOCA due to relay chatter was considered (see Section 3.1.5). Specifically, those relays which can cause the LPCI "C" injection valve to open with the reactor at high pressure were identified for seismic capacity evaluation (Table 3.1-3). Since those relays associated with LPCS, LPCI "A" and LPCI "B" are the same as LPCI "C" they were not included in Table 3.1-3. If these relays have a low seismic margin and chatter causes a seal-in signal, additional events are required to cause a LOCA in the low pressure system; (1) the injection valve has to be capable of opening under high pressure conditions, (2) failure of an upstream check valve is required to pressurize and challenge the low pressure system, and (3) the low pressure system must fail. In addition, the injection valve would have to fail to complete its cycle of opening and closing in order for the event to continue for a long duration. For these reasons, the frequency of interfacing LOCA scenarios is small regardless of the seismic margin results.

A review of typical containment isolation valves indicates that relay chatter is not a concern. Relay chatter impacts on AC power which would disable fail-as-is MOVs in the open position is the most likely scenario. AC power relays have been identified as part of the evaluation of AC power.

Functional Evaluation

This section describes the process used to determine the potential functional impact on safe shutdown systems that can result from relay chatter. This section also summarizes the evaluation for each individual system.

The functional success diagram described in Section 3.1.2.1 was used to determine specific combinations of systems that are needed to assure safe shutdown. Section 3.1.2.1 documents both development of the functional success diagram and the identification of structures, systems, and components, including relays, that must function during an earthquake. The focus of this section is on relay chatter and its impact on these systems and components. Once these systems were identified, system specific documentation was gathered. The following is a list of typical documentation reviewed for each system:

USAR
Logic Diagrams
Electrical Elementary Drawings
General Electric GEKs
Vendor prints
Electrical One-lines (where applicable)
GE Foreign Prints
P&IDs
NMPC System Descriptions

From this review, a list of systems and components that must operate or must not spuriously operate was developed. For each component identified, a review of the electrical elementary drawings was performed to determine if there were relays in the circuit that were capable of misaligning a system or causing system inoperability. The following systems were identified as being important and requiring evaluation:

Electric Power (AC & DC)
Service Water System (SW)

Reactor Core Isolation Cooling System (RCIC)
High Pressure Core Spray System (HPCS)
Automatic Depressurization System (ADS)
Low Pressure Core Spray System (LPCS)
Low Pressure Coolant Injection "C" (LPCI-C)
RHR Suppression Pool Cooling "A" (RHR-A)
RHR Suppression Pool Cooling "B" (RHR-B)

The evaluation of these major systems is described later in this section. Other support systems were evaluated on a sampling basis to ensure completeness and is summarized below:

120 Volt AC
The 120 volt vital bus uses a static inverter that contains electronic relays for critical applications. These relays are not subject to contact chatter since they do not use contacts. There are several electromechanical relays that provide alarm functions only. Chattering of these relays will not have any functional impact on operability of the UPSs.

Control room instrumentation and monitors do not use relays for their monitoring function. Auxiliary relays that are connected to the instrument loop are actuated by a solid state bistable that does not use relay contacts. Analysis of the effects of chatter of the aux relays is addressed in the systems analysis.

Room Cooling
The impact of relay chatter on cooling to critical areas of the plant was examined on a sample bases. The initial objective was to determine if the electrical control schemes used for controlling fans, unit coolers and chillers contained relays. The IPE analysis was used to identify equipment used for area cooling that was judged to be important. The area selected for analysis was the HPCS pump room. Additionally, the elementary drawings for various reactor building fans and unit coolers were surveyed for circuit design consistency. Unit coolers and fans use a starter for operation. These starters do not seal-in to the off position. Relay chatter can cause momentary stopping of fans and unit coolers but they automatically restart if there is real need for room cooling.

The control room, relay room, and computer room unit coolers use chilled water as it's primary cooling source. Service water can be used to provide backup cooling if the chillers are lost. Relay chatter of undervoltage relay 27X2-2EJSX08 and relay 1MR-2HVK16 or loss of offsite power will result in tripping off chiller compressor 2HVK*CHL1A if it was operating prior to the event. The chiller will automatically restart after tripping and is not dependent on the availability of offsite power.

Based on the above findings, relay chatter will not result in loss of unit coolers, HVAC fans or chillers nor will it require operator action to restore equipment.

Nitrogen

The nitrogen system supplies N_2 to the auto depressurization function. It is needed to keep the SRVs open for the postulated 72 hrs. The system was analyzed for the effect of relay chatter and the following conclusions were developed. The N_2 supply valves from tanks 2IAS*TK4 and 2IAS*TK5 and the containment isolation valves in the supply lines to the ADS accumulators can close due to relay chatter. The SOVs at the tanks can close but will reopen on low pressure. The N_2 containment isolation valves can also close from relay chatter. Manual operator action is needed to reopen the valves but only after a long period of time has elapsed. The relays that cause the valve to close were not included in the list of relays that were not functionally screened because manual operator action is needed to recover this N_2 supply in the long term even if these SOVs do not close. Based on the allowable time available for operator action and the need already for local actions, the effect of N_2 valve closure was considered trivial and not included.

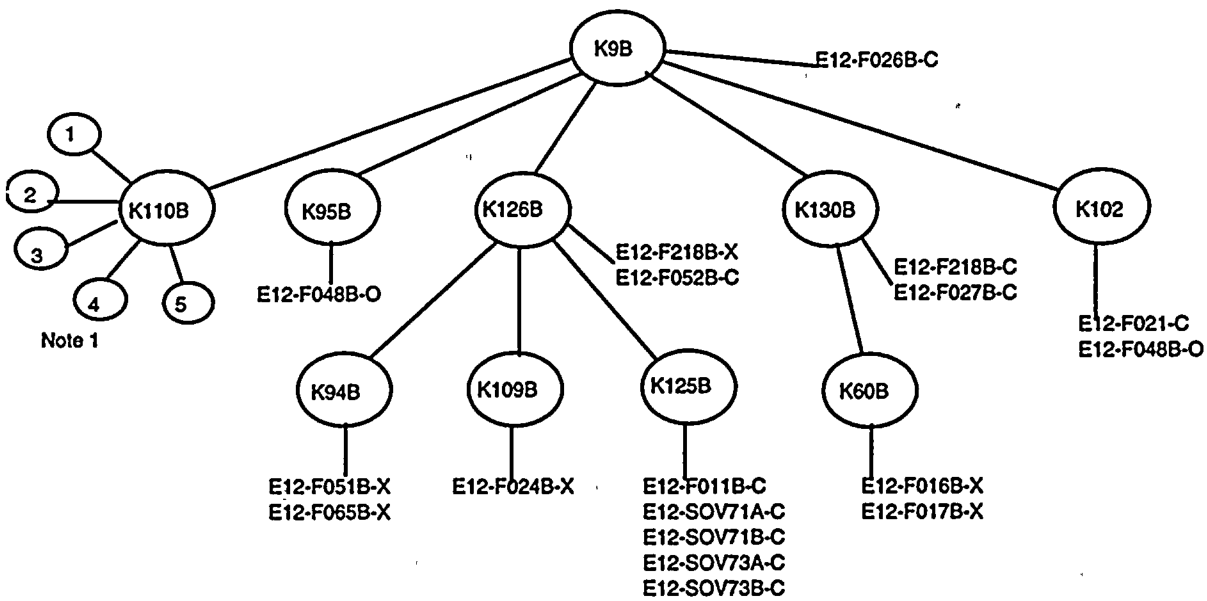
Circuit Analysis

The circuit analysis first investigated the conventional intersystem impact of relay chatter causing control circuit actuation and secondly reviewed the potential phenomenological electric intracircuit interactions. Conventional chatter analysis has focused on fluid/electric systems interaction resulting in the potential failure or degradation of systems via components being mispositioned or tripped. The second analysis focused on interactions within the electrical circuits that result in electrical transients not planned for in the original design (i.e, repeated inrush transients that result in fuse opening).

Analysis of Relay Chatter Induced System Interactions

This analysis evaluates the impact of relay chatter on the actuation of devices resulting from relay contacts closing long enough to cause a control action to occur. Circuits that do not contain relays are excluded from further evaluation. Typically, relay chatter durations of 1 ms to 500 ms need to be considered for seismic events. However, it was assumed in this analysis that the relay chatter duration was long enough to actuate relay/contactors for circuits with seal-in features. This can be reconsidered later based on relay fragility and impacts. Where several relays are identical and are located on panels that experience similar levels of acceleration, they are taken to be correlated and chatter in sync. Circuits where two relays must chatter in sync to cause actuation were also initially included even if the relays are different types and/or are located on different panels. Circuits that do not have seal-in or latching features are only affected for the duration of the chatter. The impact on systems is evaluated, but since it is only momentary it is usually functionally insignificant and screened out of this evaluation. An example is an electrically operated safety relief valve (SRV) that requires two relays to chatter in sync to cause the SRV to open momentarily. Since the SRV opening circuit does not seal-in, these relays must stay closed to keep the valve open; therefore, they can be screened out of this analysis based on the insignificant functional impact.

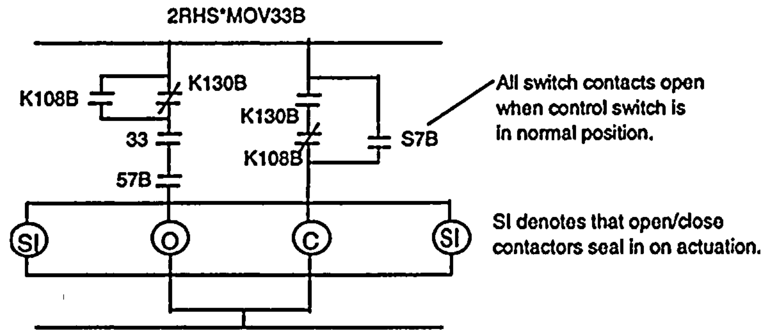
Another key factor in this analysis is the sequence of events. That is, how many relays chatter and in what order? To more readily understand this, consider the case of a master relay actuating five slave relays which in turn each actuate two other relays or components. The relay scheme below provides an example for LPCI-C and shows up to four levels of dependency. If relay K9B actuates and seals-in, all other relays K60B, K94B, K95B, K102, K109B, K110B, K125B, K126B, K130B, and relays 71X1 through 71X5 are actuated. Each relay caused actuation of one or more devices such as valves. However, if relays K110B and K130B chatter, relays K60B and relays 71X1 through 5 are actuated. This results in a significantly different functional impact as compared to the case where K9B sealed-in. To better address this issue, a relay impact diagram was used in situations where there can be multiple impacts. The various combinations were evaluated to determine impact.



Note 1: The 5 relays are 71X_-5ENS22-E

The following describes the process that was followed in investigating and documenting the functional impact of relay chatter on safe shutdown systems. To accomplish this, the chatter evaluation followed two paths, the first being the impact of individual contact closure/opening on safe shutdown components and second, the effects of a contact closure that affects many relays and safe shutdown components. This second part ties the combined impact of all impacted components.

In the first part of the evaluation, for each component that was identified as being functionally important, relevant circuit drawings (NMPC electrical drawings and GE instrument and elementary drawings) were evaluated to determine if there were relay contacts in the circuit and whether they are capable of causing a control action if actuated. This included de-energized normally closed or open contacts as well as normally energized closed or open contacts. Next, whether there are any seal-in features or there is a circuit toggle and latch was considered. The key circuit information taken from the elementary drawings was captured on a simplified sketch as shown here. Portions of the circuit that could not impact operation of the valve via relay chatter were omitted from this sketch. Limit switches, torque switches, indication lights and isolation or kill switches were omitted. Other important features of the circuit, such as interposing contacts that normally open and that are not susceptible to chatter (e.g., a SBM control switch) or switch contacts that are all normally open when the switch is in the normal or neutral position (S7B), was also recorded on the sketch.



ELECTICAL CIRCUIT RELAY SKETCH

The second part of the evaluation focused on the GE protection system circuits because these circuits crossed system boundaries. For example, a relay in the LPCI-C protection system E21A-K9B actuates RHR pump "C" relay E21A-K30B which in turn actuates several other relays that actuate many other components that may or may not have seal-in features. To more easily address this issue, a tool was developed to tie together the sum total chatter impact which is called a Relay Chatter Impact Diagram. A typical example for LPCI-C is included in a previous sketch above.

Electrical Intracircuit Analysis

Circuit analysis was performed to determine if there were any other potential circuit impacts that can be caused by relay chatter other than operation or spurious actuation. The first area investigated was the impact of relay chatter in a circuit containing electromechanical contactors such as an electrical starter in a MOV circuit that did not have any seal-in feature. The reason for this concern stems back to an event at Millstone Unit #3 which resulted from the depowering of many motor starter circuits. The specific situation resulted in the MOV control circuits experiencing a continuous inrush current (20 sec verses a normal momentary, <1 sec, inrush) that blew the control circuit fuses causing the MOV to become inoperable. MOV control circuits containing chattering relays determined that the control circuits can experience abnormal currents that were not expected in the design. Depending on the magnitude of the inrush current for a specific sized starter and the size of the control power fuse, circuit depowering as a result of relay chatter is a possibility.

This general phenomenon of prolonged inrush current can occur in any AC circuit containing an iron core inductor (solenoid or contactor). Even if the relay chatter does not depower the MOV control circuit, there is still a possibility for the power circuit to be depowered by opening of the Thermal Overloads (TOLs). In this situation, either the motor starter contactor chatters or its control relays chatter or the combined effects of both can cause repeated inrush transients. Analysis of DC circuits containing iron core inductors revealed that they do not experience a similar inrush characteristic and therefore will not be candidates for this depowering phenomenon.

The first part of the intracircuit analysis requires gathering inrush current data for contactors used in AC circuits and for the associated motors. It was assumed that the vibratory motion produced by the seismic event causes a less than continuous inrush current. This is based on the fact that inrush lasts only a few cycles. To maximize this effect, a vibratory frequency of 15 hertz was assumed and an I^2t was calculated to determine potential impact on fuses and thermal overloads. Then, this value was compared to the fuse/TOL rating to determine if the fuse/TOL would open and depower the circuit.

The second part of the intracircuit analysis evaluated the effect of a vibrating solenoid and the rapidly changing inductance would have on the current characteristics of the circuit. The primary focus is to determine the difference in pull-in current and holding current. This depends primarily on the magnetic characteristics of the solenoid which translates to the type of magnetic core, toridial or cylindrical. If the solenoid is cylindrical with a significant leakage flux, the change in current is insignificant. Otherwise, it was evaluated.

The results of this analysis determined that depowering a motor operated valve control circuit will not occur due to relay chatter. The reason for this is that the control power fuse is sized to continuously carry inrush without opening.

Thermal Overloads and their capacity to pass multiple inrush cycles was also evaluated. The thermal overloads are sized to pass continuous locked rotor current for a period of 15 seconds without opening. The equivalent I^2t developed from chatter causing 10 pulses/sec for 30 sec yields heating equivalent to having a locked rotor condition that existed for 10 seconds. This condition will not cause a 15 second thermal overload to open and depower a motor.

The last electrical phenomenon investigated was the change in inductance a relay experiences in the contactor open position versus the contactor closed position. For example, in a toroidal solenoid with a small air gap, with the contactor held open, the current can be 10 times greater than the value with the contactor closed. This condition applies to both AC and DC circuits and is significant in solenoids that have a high gap reluctance (toroidal or "C" shaped solenoids) as compared to the total magnetic circuit reluctance. In magnetic circuits with a small gap reluctance (bar or cylindrical solenoids) as compared to the total circuit reluctance, this effect is insignificant.

This last phenomenon was evaluated and determined not to cause large overcurrents associated with creation of a magnetic field or a change in inductance in DC circuits. The impact on AC circuits is covered in the analysis of inrush currents discussed above.

<u>Emergency AC power</u>
The AC power system contains components needed to provide the plant with 4Kv, 600V and 120V AC. Two conditions were analyzed: (1) the situation where offsite power is not los, and (2) the situation where offsite power is lost and the diesel generators are started and

loaded.

An evaluation of the diesel engine operation during and after an earthquake was performed. The diesel is assumed to be started after an earthquake because the earthquake is likely to cause a loss of offsite power. In the event that offsite power is not lost, the diesels need not start. Even if the diesel starts while offsite power is available, the diesel generator breaker will be prevented from closing onto a live bus. The diesel generator breaker closing circuit has an interlock that will only permit closure if the offsite power supply breakers are open. This interlock is achieved by the breaker position switch 52S contact which opens when the offsite supply breaker is closed. Because of this switch, loading the diesel onto a live bus is considered unlikely.

The remainder of this evaluation assumes that the diesel starts due to an under voltage condition. When the diesel is started on an under voltage or a LOCA signal, shutdown signals including the following are bypassed:

- high jacket coolant temperature
- low lube oil pressure
- low jacket coolant pressure

In this case, the engine will only stop on an engine overspeed or a generator electrical fault. This feature eliminates many relays from consideration since they can have no impact even if they all chatter.

The engine is started via master emergency start contactors 4EX1, 4EX2 or 4EX3. These contactors in turn actuate other relays and solenoids. Because this is a DC powered circuit, there is no current inrush associated with chatter in relays or solenoids and they cannot be depowered as in the case of AC circuits. The more likely impact is to delay startup until these relays stop chattering; however, the engine will start and run successfully.

The master contactors can chatter directly or as a result of chatter in the 27X, 86GP or the 48CL relays. However once the strong ground motion has subsided, the relays will transfer to the correct state. The net effect is to increase the starting time and waste some starting air, but there will still be sufficient starting air left to start the diesel.

Once started, the diesel generator is loaded sequentially so as to not overload the generator or slow down the engine. Sequencing is accomplished using time delay relays that pickup after the specified time interval has passed. Chatter in these relays during the loading process can cause several loads to be loaded simultaneously which overloads the generator resulting in a generator trip and lockout. The generator breaker can be tripped via relay chatter of it's protective and/or lockout relays. These relays are included in Table 3.1-3.

The supply breaker for the 4 Kv/600 V AC transformer can trip and lockout due to chatter in it's protective and/or lockout relays. This causes loss of the 600V emergency AC busses and loss of the battery charger and the 600V AC supply to the vital bus. The 125V DC bus remains functional in the short term as does the 120V AC vital bus. Long term operation of the 125V DC and 120V AC busses can be assured by reclosing the transformer supply breaker. These relays are included in Table 3.1-3.

<u>Service Water</u>
The service water system (SW) was evaluated for relay chatter effects. The primary mechanism for loss of service water is a pump trip via the breaker trip circuit relays. These relays were identified by inspecting the pump elementary drawing (ESKs). Relay contacts in the pump trip circuit that were actuated by foreign relays (relays located and actuated by other circuits) were also identified. These relays in turn were inspected by reviewing their ESKs. This process was continued until all relays were identified and added to Table 3.1-3.

<u>RCIC</u>
The Reactor Core Isolation System (RCIC) is used to provide reactor inventory makeup in the event that reactor coolant system is isolated. This system is included in the success path as being redundant to High Pressure Core Spray (HPCS) and low pressure injection systems if the RPV is depressurized.

The RCIC system uses reactor steam to power a Terry turbine driven pump. Steam is taken from the reactor, expanded through the turbine and exhausted to the suppression pool. The system is operated on an on/off mode. Water is taken from the condensate storage tank (CST) or the suppression pool and injected into the reactor vessel at a constant flow rate until a high reactor vessel water level (level 8) is reached. At that point, the system is shutdown until the water level decreases to the low water level (level 2) where the system is restarted.

The initial condition assumed in this analysis includes (1) the system in standby and starts after the seismic event is over and (2) a start signal being generated at the beginning of the seismic event. However, there is no difference between these conditions in their effect on the RCIC system's operability.

Analysis of the RCIC system determined that the system can become inoperable if the turbine is tripped or if the pump suction or discharge is blocked. The RCIC system contains numerous trip features because it uses reactor steam as a motive power source and the turbine can be a missile source. There are two modes of tripping:

1. When the RCIC turbine is tripped by it's protection system and/or when a break in the steam supply is detected, there are two redundant protection systems that detect abnormal RCIC turbine system conditions. Upon receipt of a trip signal, the turbine is tripped and one or both of the steam supply isolation valves are closed. In this case, the RCIC system can be recovered when the trip signals have cleared by restarting the system from the control room.

2. The turbine is tripped by the mechanical overspeed trip mechanism. RCIC recovery

includes manually resetting the overspeed latch locally at the turbine and restarting the system from the control room.

In addition to the above trip signals, the turbine can be tripped on mechanical overspeed if the startup valve (2ICS*MOV159) fails to open or if the steam supply valve (2ICS*MOV120) opens prematurely (before the 10 sec time delay has timed out).

The relay chatter analysis has determined that there are numerous relays that can cause a turbine trip; however, RCIC can be recovered via operator action from the control room. Table 3.1-4 summarizes the relay chatter analysis for RCIC. Recovery requires that the trip signal be reset and the steam supply isolation valves opened. Also, suction from the condensate storage tank can be lost due to chatter induced closure of 2ICS*MOV129. This valve, however, can be reopened from the control room. A turbine overspeed condition can be caused by valve 2ICS*MOV120 (i.e., opens prematurely). Recovery of RCIC from this condition requires that the operator to locally reset the trip mechanism and then open the trip valve from the control room.

<u>HPCS</u>

The High Pressure Core Spray (HPCS) system is a quasi independent system that can provide significant reactor makeup at high pressure. HPCS is powered by it's own dedicated diesel generator. The HPCS electric system provides power at the 4Kv, 600V AC, 120V AC and 125V DC levels. Normally the diesel is in standby and starts on demand. The demand signals are either a LOCA or an undervoltage condition.

The seismic event is expected to cause damage to the offsite power grid and to the switchyard. The diesel starts on bus undervoltage and trips the offsite power breaker. The diesel breaker is closed and the 4Kv AC bus, the 600V AC bus and the 120V AC vital bus are powered by the HPCS diesel. The HPCS pump remains idle until an automatic or manual start is received. Even if the diesel has not started, the seismic event can trip the diesel or prevent its starting due to lockout relays. In this situation, recovery of the diesel is possible but only if the lockout relay (K15) has been locally reset at the engine control panel. The generator lockout relays have a similar effect and they can only be reset at the HPCS switchgear. In addition, there are numerous protective relays that can cause the lockout relays to trip or could trip the supply breaker to the 4Kv/600V AC transformer.

The HPCS pump can be tripped and locked out by relay chatter in it's trip circuit, even if it is not operating. Reset requires local action at the HPCS switchgear. The pump shutoff valve, 2CSH*MOV107, can be closed via chatter of relay E22A-K13 (the high vessel level signal relay). This valve will remain closed until the low reactor vessel signal is reached. This signal deenergizes the E22A-K13. Minimum flow to suppression pool isolation valve 2CSH*MOV105 can be closed from chatter of relays E22A-K51 or K56. The valve closure circuit seals-in and closes. Once the vibratory motion has subsided, the valve will reopen. Therefore, the HPCS pump will only have operated at shutoff head while the valve was closing. This condition was assessed to have an insignificant impact. All other motor operated valves in the HPCS system either do not chatter or the effects are minimal.

For the purpose of analysis, the strong ground motion associated with an earthquake is expected to last for a period of no more than 20 sec. During this period, relays are expected to potentially chatter. Even though relays in the start circuit chatter, the majority have no effect other than delaying the startup. The one exception is the supervisory setup relay K33. The worst case chatter effect is to allow the low pressure oil trip to become active while the engine is starting. This will result in an engine shutdown and lockout of the restart until the shutdown relay is reset locally. If the engine was started on a LOCA signal, the normal engine trips are bypassed. When the engine is started on an undervoltage condition, the normal engine trips (low lube oil pressure, engine overspeed, and high coolant temperature) are not bypassed. Chatter in any of these trips can cause the engine to stop. Once tripped, the shutdown relay must be reset locally.

ADS

The Automatic Depressurization System (ADS) is used to rapidly depressurize the reactor to a pressure where the low pressure injection systems can be used. It accomplishes this by opening seven SRVs. The SRVs can also operate in a power assisted pressure relief mode. It is assumed that any real demand for the ADS function will only occur after the seismic event has subsided. By procedure, the ADS function will be inhibited until a decision for manual actuation has been made. At that point the SRVs will be manually operated.

Relay chatter in the pressure relief circuits can cause individual valves to momentarily open and close. Relay chatter in the ADS slave relays can cause several ADS valves to momentarily open and close. This only lasts while the strong motion exists. However, there are two master seal-in relays in each safeguards division that can seal-in and if both actuate due to chatter will result in a prompt blowdown of the vessel. This blowdown can occur without the mandatory time delay or a LPCI pump operating permissive. It can even occur if the reactor is operating. Subsequent operation of the ADS inhibit switch will not terminate this condition, it can only be terminated by resetting the ADS timer.

LPCS

LPCS is a low pressure coolant injection system that is used to cool the reactor core in the event that normal cooling is lost. The LPCS is used to provide emergency cooling for a large break LOCA or in conjunction with the automatic depressurization system (ADS) when the RPV is at high pressure.

Relay chatter can have different impacts on the LPCS such as starting the system, tripping the LPCS pump, and opening the injection shutoff valve while the reactor is at high pressure. Chatter of relay E21A-K12 will cause the LPCS pump to start even if the diesel generator is sequencing loads. Assuming that offsite power is lost, loading the LPCS pump on the diesel bus in the wrong sequence is expected to result in generator overload, leading to trip, lockout and loss of all loads on bus 2ENS*SWG101. Chatter of relay E21A-K12 with offsite power available starts the LPCS pump and does not cause loss of any other Division I pump.

The LPCS pump can be individually tripped off via relay chatter in it's trip circuit and locked out even if it is in a standby mode. The normally closed minimum flow valve 2CSL*MOV107 can be cycled open or closed depending if the LPCS is operating or in standby. Once the vibratory motion has ceased, the valve will return to the correct position. The pump suction MOV control circuit does not contain any relays and is not susceptible to closure.

The possibility of an interfacing systems LOCA due to relay chatter was considered. Chatter of relays E21A-K14 and K51 can cause the LPCS injection valve to open with the reactor at high pressure. These relays along with those associated with LPCI "A" and "B" were not included in Table 3.1-3. However, those relays which can cause the LPCI "C" injection valve to open with the reactor at high pressure were identified for seismic capacity evaluation (see LPCI "C" below). Those relays associated with LPCS, LPCI "A" and LPCI "B" are the same type as LPCI "C". Also, as described for LPCI "C" below, interfacing LOCA scenarios are judged to be insignificant regardless of the seismic margin results for these relays.

<u>LPCI "C"</u>
The LPCI "C" mode of operation of the RHR is used to provide a low pressure source of makeup to the reactor vessel while the reactor is at low pressure.

Relay chatter can have an impact on the operability of the LPCI pump, it's associated diesel generator, injection valve and minimum flow valve. All other valves either do not use relays in the circuit or there is an interposing set of contacts that do not chatter such as a SBM control switch.

Chatter of relay E12A-K30B can cause closure of the pump breaker. This relay is normally inhibited by the diesel sequencing circuit. Chatter of this relay can load the pump on simultaneously with other large loads and cause diesel generator 2EGS*EG3 to trip and lockout. Tripping of 2EGS*EG3 will cause all other loads on bus 2ENS*SWG103, including RHR pump B, to be lost. This impact is similar to the relay chatter impact in the LPCS pump circuit. If offsite power is not lost, chatter of E12A-K30B results in a pump start with no other adverse impact.

LPCI "C" pump can be individually tripped off and locked out if one of the pump's protective relays chatter or the lockout relay chatters.

The possibility of an interfacing systems LOCA due to relay chatter was considered. Chatter of relays E12A-K25 and K115C can cause the LPCI "C" injection valve (2RHS*MOV24C) to open with the reactor at high pressure. If these relays have a low seismic margin and chatter causes a seal-in signal, additional events are required to cause a LOCA in the low pressure system; (1) the MOV has to be capable of opening under high pressure conditions, (2) failure of an upstream check valve is required to pressurize and challenge the low pressure system, and (3) the low pressure system must fail. In addition, the MOV would have to fail to complete its cycle of opening and closing in order for the event to continue for a long duration. For these reasons, interfacing LOCA scenarios are judged to be insignificant regardless of the seismic margin results. These relays were, however, included in Table 3.1-3.

The minimum flow valve 2RHS*FV38C can momentarily cycle open and close (chatter of E12A-K54C) if the valve was initially closed. It could cycle close (chatter of E12A-K112) if initially open and return to open after the strong ground motion has subsided.

<u>RHR "A"</u>
The suppression pool cooling mode of the RHR "A" system is used to remove heat from the suppression pool and transfer it to the service water system through the RHR "A" heat exchanger. This system can be made inoperable via relay chatter resulting in pump trip.

For the purpose of this analysis, two conditions were analyzed. The first condition assumes that the power is lost and the diesel has started. The second assumes that the system is in standby.

Relay chatter during diesel start and load sequencing can result in missequencing and a diesel generator trip. Relays E12A-K3A and K18A can cause the RHR pump 2RHS*P1A to load on the diesel out of sequence and trip the generator. This causes the loss of pump 2RHS*P1A and all other loads on the bus. Recovery of the diesel requires that the generator lockout relay 86-2RHSA01 be reset locally at bus 2ENS*SWG101. The pump can also be tripped and locked out if it is operating or in standby. The lockout relay can chatter causing a pump trip or one of the protective relays could chatter causing the lockout relay to trip. Again, recovery requires that the lockout relay be locally reset.

All valves associated with RHR "A" either do not have relay contacts in their circuits or do not have a seal-in feature with two exceptions, the suppression pool spray valve (2RHS*MOV33A) and the containment spray valves (2RHS*MOV15A and 2RHS*MOV25A). These valves can cycle via relay chatter but will be correctly positioned after the strong ground motion has subsided.

The possibility of an interfacing systems LOCA due to relay chatter was considered as described for LPCI "C" above. Relays associated with LPCI "A" and "B" were not included in Table 3.1-3 because these relays are the same type as LPCI "C". Also, as described for LPCI "C" above, interfacing LOCA scenarios are judged to be insignificant regardless of the seismic margin results for these relays.

<u>RHR "B"</u>
The suppression pool cooling mode of the RHR "B" system is used to remove heat from the suppression pool. This system can be made inoperable via relay chatter resulting in a pump trip.

For the purpose of this analysis, two conditions were analyzed. The first condition assumes that the power is lost and the diesel is starting. The second assumes that the system is in standby.

Relay chatter during diesel start and load sequencing can result in missequencing and diesel generator trip. Relays E12A-K3B and K18B can cause the RHR pump 2RHS*P1B to load on the diesel out of sequence and trip the generator. This causes loss of pump 2RHS*P1B and all other loads on the bus. Recovery of the diesel requires that the generator lockout relay 86-2RHSB01 be reset locally at bus 2ENS*SWG103. The pump can also be tripped and locked out if it is operating or in standby. The lockout relay can chatter causing trip or one of the protective relays could chatter causing the lockout relay to trip. Again, recovery requires that the lockout relay be locally reset.

All valves associated with RHR "B" either do not have relay contacts in their circuits or do not have a seal-in feature with two exceptions, the suppression pool spray valve (2RHS*MOV33B) and the containment spray valves (2RHS*MOV15B and 2RHS*MOV25B). These valves can cycle via relay chatter but will correctly reposition themselves after the strong ground motion has subsided.

The possibility of an interfacing systems LOCA due to relay chatter was considered as described for LPCI "C" above. Relays associated with LPCI "A" and "B" were not included in Table 3.1-3 because these relays are the same type as LPCI "C". Also, as described for LPCI "C" above, interfacing LOCA scenarios are judged to be insignificant regardless of the seismic margin results for these relays.

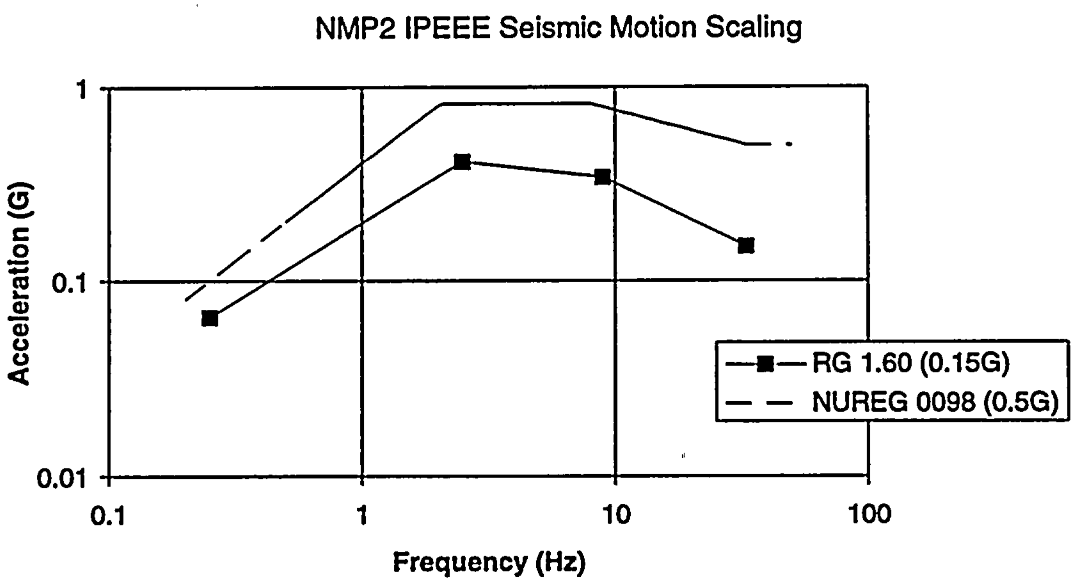
<u>Functional Evaluation Sketches</u>
Several sketches were drafted during the functional evaluation of relay chatter described above. These sketches are contained in the tier 2 documentation[9].

3.1.3 Analysis of Structure Response[21, 22]

Design response spectra were developed in accordance with Regulatory Guide 1.60. Sections 3.7 and 3.8 of the USAR[6] describe in detail the seismic and structural design. The required Floor Response Spectra (FRS) for NMP2 Seismic Margins Analysis was developed using scaling techniques, which scales from the design basis FRS, as recommended in Section 4 of EPRI NP-6041[11]. The scale factor is defined by the ratio of the average Ground Response Spectrum (GRS) between the Seismic Margin Earthquake and the Design Basis Earthquake around +/-15% building fundamental frequency. The design basis earthquake is the Regulatory Guide 1.60 GRS scaled to a peak ground acceleration (PGA) of 0.15g.

Although NUREG-1407[3] only required a 0.3g Review Level Earthquake (RLE) evaluation, the RLE for NMP2 is based on the Median spectral shape defined in NUREG-0098[20] scaled to 0.5g PGA. The seismic capacity of NMP2 was expected to be high; utilizing a 0.5g RLE would provide more knowledge relative to the seismic capability of the plant. Since NMP2 is a rock site, the v/a or peak ground velocity to peak ground acceleration ratio of 36 in/sec/g was used according to the recommendations in NUREG-0098.

According to EPRI NP-6041[11], pages 4-11 to 4-18, the scaling technique is acceptable if the plant is located on a rock site and the two spectra are similar in shape. For the NMP2 scaling application, both conditions are satisfied. Both spectra are relatively rich in low frequency power and peak at about the same frequency range. The two GRS are compared in the following chart.



The design basis damping is based on Regulatory Guide 1.61, where 7% critical damping is used for the reinforced concrete structures. For the SMA study, according to EPRI NP-6041, Table 4-1, reinforced concrete structures could reach 10% damping beyond yield or just below yield, which is reasonable for a Seismic Margin Study. However, since the FRS will be used for equipment HCLPF evaluations, a 7% damping identical to the SSE was used.

Based on the design basis response spectra, governing frequencies were selected for each building structure. The spectral values were interpolated from the original 7% Regulatory Guide 1.60 response spectra, the time history response spectra, and the 7% NUREG-0098 response spectra. Since the design basis defines the vertical motion at 0.15g vertical Regulatory Guide 1.60, the RLE for the vertical motion is defined as the same as the horizontal directions. The scale factors are then determined from the ratio between the RLE spectral values and the safe shutdown earthquake (SSE) spectral values around the dominant building frequencies (+/- 15%).

The following NMP2 major structures were prescreened based on a review of plant documentation and the guidelines given in EPRI NP-6041, Table 2-3[11]:

Type of Structure	NMP2 Structure	0.8-1.2g 5% dmp
Concrete Containment	primary containment	note a
	secondary containment	note a
Containment Internal Structures	reactor vessel & supports	note f
	drywell and suppression pool structures	note f
	drywell floor	note f
Containment Shield Walls	biological shield wall	note f
Category I Concrete Frame Structures	control building	note f
	diesel generator building	note f
	service water intake & discharge structure	note f
	main steam tunnel	note f
	spent fuel pool	note f
	service water screenhouse	note f
	pipe tunnel	note f
	electric tunnel	note f

The prescreening note clarifications in the above table and the EPRI table are explained here:

- note a - for the primary and secondary containment structures penetrations should be evaluated. This was documented in the SEWS[10] with a 0.5g HCLPF.

- note f - if structures are designed to ACI 318-71 or later editions, additional evaluation is not required. NMP2 structures meet this and it is documented in the SEWS.

The following further summarizes the evaluation of passive structures and components in Table 1 and documented in SEWS (all structures and components have a 0.5g HCLPF).

The primary containment was walked down including the drywell, vacuum breakers, penetrations, reactor coolant pressure boundary, and instrument lines. Mechanical and electrical penetrations were reviewed, as well as personnel, emergency, and equipment hatches. Seismic category structures were walked down, or if inaccessible, a drawing review was performed. Again, penetrations were reviewed. All structures are separated by a 3 inch gap to prevent impact and NMP2 is a rock site free from soil failure issues.

Reactor vessel supports and internals, CRD housings, and recirculating pumps were evaluated. Safety related seismically designed piping can be screened out at relatively high accelerations. Reviews were performed and a piping system walked down to verify design adequacy. Other piping systems were observed during the walkdown. Fire piping, not generally seismic designed, is mostly rod-hung, steel welded piping. The potential for a fire water flood was evaluated and considered during the walkdown. The potential for a deluge valve opening due to trim piping being crushed (i.e., hitting the wall) was identified as a potential problem -- the deluge valve opening flooded downstream piping with Victualic couplings. This was assumed to flood the control building elevation containing the emergency switchgear. Subsequent assessments determined that the fire water header movement would not crush the trim piping and a 0.5g HCLPF was demonstrated.

Ductwork was inspected, in general, throughout the plant. Particular attention was given to ducting inside the containment and inside the battery rooms where collapse could short circuit the emergency batteries.

The electrical raceways were inspected. Most supports were of structural steel or braced light metal strut construction and well anchored. Even small conduit lines were rigidly supported.

3.1.4 Evaluation of Seismic Capabilities of Components and Plant[10,21,22,23,24]

The seismic review team walked down most major components identified in Table 3.1-1A and 1B and determined that a HCLPF of 0.5g or greater exists for the seismic margin earthquake for most components as documented in the seismic evaluation work sheets (SEWS)[10]. Based on the walkdown, and because of equipment configuration or accessibility limitations, certain components could not be screened out during the walkdown. Calculations[22,23,24] document the review process and HCLPF calculations for these components. These calculations are performed in accordance with EPRI NP-6041[11]. With one exception, all calculations indicate a HCLPF of 0.5g or greater. The one exception is relay chatter for HFA Model 154 relays. This HCLPF is 0.45g, but the calculation is based on the worst case required response spectra in the switchgear. Also, the acceptance criteria for relay chatter was 2 ms which is unlikely to cause an impact at NMP2. For these reasons, and since other conservatisms exist, it is judged that a plant HCLPF of 0.5g or greater exists and this is also assumed in the seismic PRA analysis in Section 3.2.

The following summarizes the scope and results of NMPC Calculations[22,24] in terms of PGA expressed as a HCLPF value:

- Motor Operated Valves (0.5g to >1g depending on method & qualification)
- Reactor Internals (0.5g)
- RHR Heat Exchangers (1g)
- Emergency Diesel Room Fans (2g)
- Switchgear (0.5g)
- Motor Control Centers (0.5g)
- Battery Racks (0.7g)
- Instrument Air Tank - Nitrogen to ADS SRVs (0.7g)
- Diesel Generators (0.5g)
- Fire Protection Water Line (0.5g)
- Relay Chatter (0.45g to >0.5g)

The above HCLPFs are judged to be conservative. Also, the SEWS reference these NMPC calculations[22]. In many cases, equipment was inspected and screened based on seismic review team knowledge and review. Component anchorages were not screened; rather, worst case representative anchorages were selected for analysis to ensure they possessed HCLPFs equal to or higher than the equipment class HCLPF value.

N2 tanks were found to have a HCLPF of 0.23g due to seismic interaction with other nearby tanks. As a result of the walkdown, it was decided not to take credit for nitrogen systems for long term ADS or containment venting with regard to establishing a 0.5g plant HCLPF. The removal success paths did not affect the SMA since there were still two redundant success paths. This is discussed further in Section 3.1.2. The seismic PRA in Section 3.2 provides risk insights into the value of ADS and containment venting.

3.1.5 Analysis of Containment Performance[8,9]

The containment pressure boundary, including structures, piping, valves and penetrations are included in Table 3.1-1A. These components are expected to have high seismic capacities.

The containment penetrations screening analysis in the IPE was reviewed. The following summarizes typical containment isolation valve alignments and the associated seismic capability scope:

Containment Isolation Alignment	Seismic Capability Scope
closed & no auto open signal	penetration, isolation valves, and piping between valves (1) and penetration
open - auto closure signal (non-ECCS)	same as closed plus isolation valve actuators, signal, and support systems (2)
open - no closure signal (ECCS) or closed - auto open signal (ECCS)	same as closed plus ECCS piping and system pressure boundary(3)

(1) A closed system inside or outside containment may provide backup to valve disc rupture.

(2) A closed system inside or outside containment may provide backup to isolation valve failure to close.

(3) Operator action as a backup is neglected.

The containment isolation system is normally energized and the loss of electrical support results in a containment isolation. In addition, many normally open isolation valves fail closed on loss of their actuator support (i.e., instrument air, 120V AC power and nitrogen). Other normally open paths are associated with closed systems or emergency core cooling and containment systems. The seismic capability of these closed systems is expected to be high as with piping systems above. The following valve types are included to assure that containment isolation capability is considered in the seismic capacity assessment:

- Typical main steam isolation valves (2MSS*AOV6A & 7A) which fail closed on loss of support. The IPE model neglected these paths because of reliability in closing and additional turbine valves that provide redundancy. The seismic capability of the MSIVs is checked to avoid having to assess turbine stop & control valves and associated piping.

- Typical drywell/suppression chamber purge valves (2CPS*AOV109 & 111) which fail closed on loss of support. The IPE includes the frequency that the valves are expected to be open during power operation. 2CPS*AOV109 and associated solenoid operated valves are included in Table 3.1-1B. These valves would have to open to support the containment venting function, however, this was dropped from the success diagram during the walkdown as discussed in Section 3.1.2.

- Typical floor & equipment drain paths (2DFR*MOV121 & 120) which fail as is on loss of support. The IPE includes operator actions to locally isolate the outside MOV in these paths during a station blackout.

In addition, penetration configurations and the potential for spatial interactions were considered during the walkdown.

From an accident sequence perspective, the most likely scenario associated with potential core damage and an unisolated containment could be a station blackout where the operators have to isolate normally open motor operated valves (MOV) that fail as is on loss of emergency AC power.

The potential for causing a LOCA outside containment is unlikely because the containment isolation function is seismically rugged (i.e., MSIV closure, feedwater check valves and associated piping). The potential for causing an interfacing systems LOCA was also considered from the IPE as described below:

- Shutdown cooling suction & discharge and steam condensing suction paths to RHR "A" and "B" have at least two normally closed MOVs and one of the MOVs is de-energized.

- RHR "B" head spray (through RCIC head spray) has several check valves and a normally closed MOV.

- The LPCS and LPCI "A", "B" and "C" injection paths have a normally closed MOV and a check valve. The MOV in each path receives a permissive to open on low differential pressure <u>and</u> pump start signal or manual system initiation signal. It is doubtful that the MOV would even open under normal reactor pressure.

A seismic caused interfacing LOCA is unlikely based on the above because several valve discs would have to fail and the seismic capacity of valves is very high. Also, in the case of the injection paths, relay chatter causing the permissive would require a check valve disc failure. This is unlikely even if we assume the MOV can actually open at reactor pressure and the LPCS and RHR piping systems will fail (IPE assessed these systems to have high likelihood of survival).

<u>Relay Chatter</u>
The impact of relay chatter on containment isolation was evaluated. The evaluation was

performed on a sample bases rather than analyzing every valve that performs a containment isolation function. This is acceptable because there are standard circuit designs used for each class of valve (MOV, AOV, and SOV). The IPE was reviewed to select valves that were included in the IPE model. The valves chosen for circuit analysis were 2DER*MOV120, 2CPS*AOV111, and 2CPS*SOV111.

For MOVs, there are no seal-in features in the open circuit that can be actuated by relay chatter. Once closed, the valve cannot be opened by relay chatter. Even if the containment isolation signal has been reset, the valve can only be opened by operator action. The valve fails-as-is on loss of power, therefore, relay chatter that trips out AC power to the MOV is possible. This AC power evaluation is discussed in Section 3.1.2.

An AOV cannot be opened unless it is a manual operation to open the valve and certain permissive relays have been satisfied or at least two relays in the open circuit chatter in addition to the manual operation. All AOVs used for containment isolation "fail closed" on loss of air.

All SOVs are de-energize to close. The analysis of the SOV circuits used for containment isolation valves is covered the same as the analysis of AOVs.

The analysis demonstrates that relay chatter is not a creditable mechanism for failing the containment isolation function except for the AC power dependency for MOVs.

Interfacing LOCA events were also determined to be very unlikely as described above for LPCS and LPCI.

Table 3.1-1A
Passive Structures, Systems & Components

- Primary containment [PC]
  - drywell & suppression structures (PCI)
  - drywell floor (VS)
  - downcomers (VS)
  - vacuum breaker lines (VS)
  - vacuum breaker check valves (VS)
  - penetrations including piping (PCI)

- Reactor vessel and supports (LOCA)

- Reactor coolant pressure boundary
  - reactor recirculation pumps & supports (LOCA)
  - main steam & feedwater piping (LOCA)
  - recirc loop piping (LOCA)
  - safety relief valves (SRV)
  - main steam isolation valves (PCI & LOCA)
  - feedwater isolation valves (PCI & LOCA)
  - SRV piping to the suppression pool (LOCA)
  - connecting piping to ECCS (LOCA)

- Reactor internals (SCRAM)

- CRD housing, HCUs & supports (SCRAM & LOCA)[SC 261']

- Instrument lines including reference leg condensing pots (part of NSSS RCPB)

- Secondary containment structures [SC]
  - Reactor building [RB]
  - North auxiliary bay [ABN]
  - South auxiliary bay [ABS]
  - Spent fuel pool
  - Penetration Seals that interface with the turbine building through the pipe tunnels {included due to circulating water system floods in the turbine building. Includes electrical and mechanical penetrations, Drawings 12177-EE-37L-13 and 37M-12, and 12177-EP-116D-17, 116E-18, and 116F-19}

Table 3.1-1A
Passive Structures, Systems & Components

- Control Building [CB]
  - Battery Room [CBR]
  - Control A/C Room [CCA]
  - Chiller Room [CCL]
  - Control Room [CCR]
  - Relay Room [CRR]
  - SWGR DIV I [CSA]
  - SWGR DIV II [CSB]
  - SWGR HPCS [CSH]
  - Tray Routing [CTR]
- Diesel Generator Building [DG]
- Service Water Area & Valve Pit [SW & SVP]
- Service water intake and discharge tunnels & piping [ITK]
- Main Steam Tunnel [MST]
- Nitrogen Area [NA]
- Pipe Tunnel [PT]
- Electrical Tunnel [ET]
- Safety piping outside containment
- Non-safety piping outside containment
- Fire water piping
- Valves (pressure boundary)
- Check Valves
- RHR heat exchangers
- Cable trays
- Fuses

Table 3.1-1A
Passive Structures, Systems & Components

- Main control room panels & ceiling
- Service water expansion joints
- Switches

(1) Acronyms in parentheses, indicate systems and components defined in the functional success diagram, Figure 3.1-1. Acronyms in brackets "[]" represent buildings and structures where equipment identified in Table 1B are located.

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
	2CEC*PNL603	N/A	PNL	Neutron Monitoring Panel	5	CB	306.00
	2CEC*PNL608	N/A	PNL	Neutron Monitoring Panel	5	CB	306.00
	2CEC*PNL618	N/A	PNL	RHR relay Panel	5	CB	306.00
	2CEC*PNL621	N/A	PNL	RCIC relay Panel	5	CB	306.00
	2CEC*PNL629	N/A	PNL	RHR/RCIC relay Panle	5	CB	306.00
	2CEC*PNL829	N/A	PNL	ADS RELAY CABINET	5	CB	288.00
	2CEC*PNL838	N/A	PNL	MISC RELAY CABINET	5	CB	288.00
	2CEC*PNL859	N/A	PNL	SCO realy Panel	5	CB	288.00
	2CEC*PNL861	N/A	PNL	SCO realy Panel	5	CB	288.00
	2CEC*PNL870	N/A	PNL	MISC realy Cabinet	5	CB	306.00
	2CEC*PNL871	N/A	PNL	MISC realy Cabinet	5	CB	306.00
	2CEC*PNL874	N/A	PNL	Containment Monitoring Cabinet	5	CB	288.00
	2CEC*PNL873	N/A	PNL	Containment Monitoring Cabinet	5	CB	306.00
	2CEC*PNL890	N/A	PNL	Containment Monitoring Cabinet	5	CB	288.00
	2CEC*PNL898	N/A	PNL	Containment Monitoring Cabinet	5	CB	306.00
	2CEC*PNL895	N/A	PNL	Containment Monitoring Cabinet	5	CB	288.00
	2CEC*PNL894	N/A	PNL	Containment Monitoring Cabinet	5	CB	288.00
	2CEC*PNL891	N/A	PNL	Containment Monitoring Cabinet	5	CB	288.00
	2CES*RAK105	N/A	Inst Rack	Containment Monitoring Rack	6	SC	261.00
	2CES*RAK027	N/A	Inst Rack	ECCS Inst Rack	6	SC	261.00
	2CES*RAK026	N/A	Inst Rack	ECCS Inst Rack	6	SC	261.00
	2CES*RAK010	N/A	Inst Rack	ECCS Inst Rack	6	SC	261.00
	2CES*RAK009	N/A	Inst Rack	ECCS Inst Rack	6	SC	261.00
	2CES*RAK005	N/A	Inst Rack	ECCS Inst Rack	6	SC	261.00
	2EGS*PNL028	N/A	Inst Rack	ECCS Inst Rack	0	CB	261.00
	2LAC*PNL300B		PNL	600 VAC Distribution Panel	7	CB	261.00
	2LAC*PNL100A		PNL	600 VAC Distribution Panel	7	CB	261.00
	2CES*RAK004		Inst Rack	ECCS INST RACK	6	SC	261.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
RCIC	2CES*RAK017		Inst Rack	RCIC Inst Rack		SC	175.00
AC	2EJS*PNL101A		PNL	600VAC Distribution Panel	7	ABN	240.00
AC	2EJS*PNL102A		PNL	600VAC Distribution Panel	7	ABN	240.00
AC	2EJS*PNL104A		PNL	600VAC Distribution Panel	7	ABN	240.00
AC	2EJS*PNL301B		PNL	600VAC Distribution Panel	7	ABS	240.00
AC	2EJS*PNL302B		PNL	600VAC Distribution Panel	7	ABS	240.00
AC	2EJS*PNL304B		PNL	600VAC Distribution Panel	7	ABS	240.00
AC	2SCM*PNL101A		PNL	120VAC Distribution Panel	7	CB	288.00
AC	2SCM*PNL301A		PNL	120VAC Distribution Panel	7	CB	288.00
AC	2EGA*TK1A		TANK	Air start receiver tanks	19	DG	261.00
AC	2EGA.TK2A		TANK	Air start receiver tanks	19	DG	261.00
AC	2EGA*TK1B		TANK	Air start receiver tanks	19	DG	261.00
AC	2EGA*TK2B		TANK	Air start receiver tanks	19	DG	261.00
AC	2EGF*TK3A		TANK	Fuel Oil Day tank	19	DG	261.00
AC	2EGF*TK3B		TANK	Fuel Oil Day tank	19	DG	261.00
HPCS	2EGF*TK4		TANK	Fuel Oil Day tank	19	DG	261.00
HPCS	2EGA*TK3		TANK	Air start receiver tanks	19	DG	261.00
HPCS	2EGA*TK4		TANK	Air start receiver tanks	19	DG	261.00
AC	2CES*IPNL406			DG Control Panel	5	DG	261.00
AC	2CES*IPNL407			DG Control Panel	5	DG	261.00
AC	2CES*IPNL408			DG Control Panel	5	DG	261.00
AC	2CES*IPNL412			DG Control Panel	5	DG	261.00
HPCS	2CES*IPNL413			DG Control Panel	5	DG	261.00
HPCS	2CES*IPNL414			DG Control Panel	5	DG	261.00
AC	2EGS*PNL11			DG Control Panel	5	DG	261.00
AC	2EGS*PNL31			DG Control Panel	5	DG	261.00
HPCS	2EGF*IPNL112			DG Control Panel	5	DG	261.00
RCIC	2ICS*PT105			RCIC Pump Suction Press Xmtr			

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
RCIC	2ICS*PIS105			RCIC Pump Suction Press Switch			
DC	2BYS*PNL204A			DC Distribution Panel	7	DG	261.00
DC	2BYS*PNL204B			DC Distribution Panel	7	DG	261.00
AC	27X3-2ENSX04	2ENS*SWG101	HFA	TRAIN A LOAD SHED RELAY	25	CSA	261.00
AC	27X3-2ENSY04	2ENS*SWG103	HFA	TRAIN B LOAD SHED RELAY	25	CSA	261.00
AC	2BYS*SWG002A-3C	N/A	ACB	125VDC SUPPLY TO : 2VBA*UPS2A	0	CSA	261.00
AC	2BYS*SWG002B-3C	N/A	ACB	125VDC SUPPLY FROM : 2VBA*UPS2B	0	CSB	261.00
AC	2C-2ENSX04	2ENS*SWG101	AGA (TDPU)	TIME DELAY RELAY (SWGR 2ENS*SWG101 CONTROL BUS UV & LOAD SEQUENCING)	25	CSA	261.00
AC	2C-2ENSY04	2ENS*SWG103	AGA (TDPU)	TIME DELAY RELAY (SWGR 2ENS*SWG103 CONTROL BUS UV & LOAD SEQUENCING)	25	CSB	261.00
AC	2D-2ENSX04	2ENS*SWG101	AGA (TDPU)	TIME DELAY RELAY (SWGR 2ENS*SWG101 CONTROL BUS UV & LOAD SEQUENCING)	25	CSA	261.00
AC	2D-2ENSY04	2ENS*SWG103	AGA (TDPU)	TIME DELAY RELAY (SWGR 2ENS*SWG103 CONTROL BUS UV & LOAD SEQUENCING)	25	CSB	261.00
AC	2EGF*P1A	LOCAL	P	FUEL TRANSFER PUMP	12	DG	261.00
AC	2EGF*P1B	LOCAL	P	FUEL TRANSFER PUMP	12	DG	261.00
AC	2EGF*P1C	LOCAL	P	FUEL TRANSFER PUMP	12	DG	261.00
AC	2EGF*P1D	LOCAL	P	FUEL TRANSFER PUMP	12	DG	261.00
AC	2EGS*EG1	LOCAL	EG	DIESEL GENERATOR 1	9	DG	261.00
AC	2EGS*EG3	LOCAL	EG	DIESEL GENERATOR 3	9	DG	261.00
AC	2EHS*MCC101	N/A	MCC	EMER MCC 101	1	SW	261.00
AC	2EHS*MCC101-10A	N/A	ACB	EMER MCC 101 INCOMING BREAKER	0	SW	261.00
AC	2EHS*MCC101-1A	N/A	ACB	EMER MCC 101 INCOMING BREAKER	0	SW	261.00
AC	2EHS*MCC102	N/A	MCC	EMER MCC 102	1	ABN	240.00
AC	2EHS*MCC102-13A	N/A	ACB	EMER MCC 102 STARTER BUS TIE BREAKER	0	ABN	240.00
AC	2EHS*MCC102-1A	N/A	ACB	EMER MCC 102 INCOMING BREAKER	0	ABN	240.00
AC	2EHS*MCC102-22A	N/A	ACB	EMER MCC 102 INCOMING BREAKER	0	ABN	240.00
AC	2EHS*MCC103	N/A	MCC	EMER MCC 103	1	CSA	261.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
AC	2EHS*MCC103-16A	N/A	ACB	EMER MCC 103 BUS TIE BREAKER	0	CSA	261.00
AC	2EHS*MCC103-1A	N/A	ACB	EMER MCC 103 INCOMING BREAKER	0	CSA	261.00
AC	2EHS*MCC103-27A	N/A	ACB	EMER MCC 103 INCOMING BREAKER	0	CSA	261.00
AC	2EHS*MCC301	N/A	MCC	EMER MCC 301	1	SW	261.00
AC	2EHS*MCC301-1A	N/A	ACB	EMER MCC 301 INCOMING BREAKER	0	SW	261.00
AC	2EHS*MCC301-8A	N/A	ACB	EMER MCC 301 INCOMING BREAKER NO CABLE NO 2EHSBYL216 , 217	0	SW	261.00
AC	2EHS*MCC302	N/A	MCC	EMER MCC 302	1	ABS	240.00
AC	2EHS*MCC302-11A	N/A	ACB	EMER MCC 302 BUS TIE BREAKER	0	ABS	240.00
AC	2EHS*MCC302-1A	N/A	ACB	EMER MCC 302 INCOMING BREAKER FROM 2EJS*US3 BRKR 3C	0	ABS	240.00
AC	2EHS*MCC302-22A	N/A	ACB	EMER MCC 302 INCOMING BREAKER	0	ABS	240.00
AC	2EHS*MCC303	N/A	MCC	EMER MCC 303	1	CSB	261.00
AC	2EHS*MCC303-13A	N/A	ACB	EMER MCC 303 BUS TIE BREAKER BUS TIE TO MCC 2EHS*MCC303 COMPT 12A	0	CSB	261.00
AC	2EHS*MCC303-1A	N/A	ACB	EMER MCC 303 INCOMING BREAKER	0	CSB	261.00
AC	2EHS*MCC303-24A	N/A	ACB	EMER MCC 303 INCOMING BREAKER	0	CSB	261.00
AC	2EJS*PNL100A	N/A	PNL	600 VAC PANEL	5	CSA	261.00
AC	2EJS*PNL100A-7	N/A	ACB	CIRCUIT BREAKER FOR POWER TO 2VBA*UPS2A1	0	CSA	261.00
AC	2EJS*PNL300B	N/A	PNL	600 VAC PANEL	5	CSB	261.00
AC	2EJS*PNL300B-7	N/A	ACB	CIRCUIT BREAKER FOR POWER TO 2VBS*UPS2B1	0	CSB	261.00
AC	2EJS*US1	2EJS*US1	US	600V U.S EMERGENCY SWITCHGEAR	1	CSA	261.00
AC	2EJS*US1-3B	2EJS*US1	ACB	MAIN BREAKER	0	CSA	261.00
AC	2EJS*US1-3C	2EJS*US1	ACB	FEEDER BREAKER TO : 2EHS*MCC102 (1A)	0	CSA	261.00
AC	2EJS*US1-4B	2EJS*US1	ACB	FEEDER BREAKER TO : 2EHS*MCC101 (1A)	0	CSA	261.00
AC	2EJS*US1-5D	2EJS*US1	ACB	FEEDER BREAKER TO : 2EHS*MCC103 (1A)	0	CSA	261.00
AC	2EJS*US1-7D	2EJS*US1	ACB	FEEDER BREAKER TO : 2EHS*MCC103 (27A)	0	CSA	261.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
AC	2EJS*US1-8C	2EJS*US1	ACB	FEEDER BREAKER TO : 2EHS*MCC102 (22A)	0	CSA	261.00
AC	2EJS*US1-9B	2EJS*US1	ACB	MAIN BREAKER	0	CSA	261.00
AC	2EJS*US1-9C	2EJS*US1	ACB	FEEDER BREAKER TO : 2EHS*MCC101 (10A)	0	CSA	261.00
AC	2EJS*US3	2EJS*US3	US	600V US EMER SWGR	1	CSB	261.00
AC	2EJS*US3-3B	2EJS*US3	ACB	MAIN BREAKER	0	CSB	261.00
AC	2EJS*US3-3C	2EJS*US3	ACB	FEEDER BREAKER TO : 2EHS*MCC302 (1A)	0	CSB	261.00
AC	2EJS*US3-4B	2EJS*US3	ACB	FEEDER BREAKER TO : 2EHS*MCC301 (1A)	0	CSB	261.00
AC	2EJS*US3-5D	2EJS*US3	ACB	FEEDER BREAKER TO : 2EHS*MCC303 (1A)	0	CSB	261.00
AC	2EJS*US3-7D	2EJS*US3	ACB	FEEDER BREAKER TO : 2EHS*MCC303 (24A)	0	CSB	261.00
AC	2EJS*US3-8C	2EJS*US3	ACB	FEEDER BREAKER TO : 2EHS*MCC302 (22A)	0	CSB	261.00
AC	2EJS*US3-9B	2EJS*US3	ACB	MAIN BREAKER	0	CSB	261.00
AC	2EJS*US3-9C	2EJS*US3	ACB	FEEDER BREAKER TO : 2EHS*MCC301 (8A)	0	CSB	261.00
AC	2EJS*X1A	LOCAL	X	4160/600V EMER XFMR 1A LOCATED IN 2EJS*US1 CUB 2	4	CSA	261.00
AC	2EJS*X1B	LOCAL	X	4160/600V EMER XFMR 1B LOCATED IN 2EJS*US1 CUB10	4	CSA	261.00
AC	2EJS*X3A	LOCAL	X	4160/600V EMER XFMR 3A LOCATED IN 2EJS*US3 CUB 2	4	CSB	261.00
AC	2EJS*X3B	LOCAL	X	4160/600V EMER XFMR 3B LOCATED IN 2EJS*US3 CUB 10	4	CSB	261.00
AC	2ENS*SWG101	N/A	SWG	4160 EMER SWGR 101	1	CSA	261.00
AC	2ENS*SWG101-1	N/A	ACB	CIRCUIT BREAKER FOR 2EGS*EG1	0	CSA	261.00
AC	2ENS*SWG101-13	N/A	ACB	CIRCUIT BREAKER FOR 2NNS-SWG016	0	CSA	261.00
AC	2ENS*SWG101-14	N/A	ACB	CIRCUIT BREAKER FOR 2EJS*X1A	0	CSA	261.00
AC	2ENS*SWG101-2	N/A	ACB	CIRCUIT BREAKER FOR 2EJS*X1B	0	CSA	261.00
AC	2ENS*SWG103	N/A	SWG	4160 EMER SWGR 103	1	CSB	261.00
AC	2ENS*SWG103-1	N/A	ACB	CIRCUIT BREAKER FOR 2EJS*X3A	0	CSB	261.00
AC	2ENS*SWG103-13	N/A	ACB	CIRCUIT BREAKER FOR 2EJS*X3B	0	CSB	261.00
AC	2ENS*SWG103-14	N/A	ACB	CIRCUIT BREAKER FOR 2EGS*EG3	0	CSB	261.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
AC	2ENS*SWG103-4	N/A	ACB	CIRCUIT BREAKER FOR NORMAL POWER SUPPLY FROM 2NNS-SWG017-2	0	CSB	261.00
AC	2HVP*AOD4A	LOCAL	AOD	INLET DMPR	13	DG	284.00
AC	2HVP*AOD4B	LOCAL	AOD	INLET DMPR	13	DG	284.00
AC	2HVP*AOD4C	LOCAL	AOD	INLET DMPR	13	DG	284.00
AC	2HVP*AOD4D	LOCAL	AOD	INLET DMPR	13	DG	284.00
AC	2HVP*FN1A	LOCAL	FN	AXIAL FAN - DG DIV I	17	DG	275.00
AC	2HVP*FN1B	LOCAL	FN	AXIAL FAN - DG DIV II	17	DG	275.00
AC	2HVP*FN1C	LOCAL	FN	AXIAL FAN - DG DIV I	17	DG	275.00
AC	2HVP*FN1D	LOCAL	FN	AXIAL FAN - DG DIV II	17	DG	275.00
AC	2HVP*FS8A	LOCAL	FS	FLOW SWITCH	8	DG	280.00
AC	2HVP*FS8B	LOCAL	FS	FLOW SWITCH	8	DG	280.00
AC	2HVP*FS8C	LOCAL	FS	FLOW SWITCH	8	DG	280.00
AC	2HVP*FS8D	LOCAL	FS	FLOW SWITCH	8	DG	280.00
AC	2HVP*MOD1A	LOCAL	MOD	MOTOR OPERATED DAMPER	14	DG	279.00
AC	2HVP*MOD1B	LOCAL	MOD	MOTOR OPERATED DAMPER	14	DG	279.00
AC	2HVP*MOD1C	LOCAL	MOD	MOTOR OPERATED DAMPER	14	DG	279.00
AC	2HVP*MOD1D	LOCAL	MOD	MOTOR OPERATED DAMPER	14	DG	279.00
AC	2HVP*TIS120	LOCAL	TIS	TEMPERATURE SWITCH FOR 2HVP*UC1C	8	DG	269.00
AC	2HVP*TIS13A	LOCAL	TIS	TEMPERATURE SWITCH FOR 2HVP*UC1A	8	DG	265.00
AC	2HVP*TIS13B	LOCAL	TIS	TEMPERATURE SWITCH FOR 2HVP*UC1B	8	DG	272.00
AC	2HVP*UC1A	LOCAL	UC	UNIT COOLER FOR STANDBY DIESEL GENERATOR ROOM (DG1)	18	DG	280.00
AC	2HVP*UC1B	LOCAL	UC	UNIT COOLER FOR STANDBY DIESEL GENERATOR ROOM (DG3)	18	DG	280.00
AC	2LAC*PNL100A-19	N/A	ACB	POWER TO : 2VBA*UPS2A	0	CSA	261.00
AC	2LAC*PNL300B-19	N/A	ACB	POWER TO : 2VBA*UPS2B	0	CSB	261.00
AC	2SWP*MOV66A	LOCAL	MOV	MOV, SWP FR CLR 2EGS*EG1	14	DG	271.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
AC	2SWP*MOV66B	LOCAL	MOV	MOV, SWP FR CLR 2EGS*EG3	14	DG	269.00
AC	2VBA*UPS2A	LOCAL	UPS	UNINTERRUPTIBLE PWR SUPP INCLUDING REG TRANSFORMER&MANUAL BYPASS SWITCH	3	CSA	261.00
AC	2VBA*UPS2B	LOCAL	UPS	UNINTERRUPTABLE PWR SUPP INCLUDING REG TRANSFORMER & MANUAL BYPASS SWITCH	3	CSB	261.00
AC	2VBS*PNL101A	N/A	PNL	120 VAC VITAL BUS	7	CTR	288.00
AC	2VBS*PNL102A	N/A	PNL	120 VAC VITAL BUS	7	CTR	288.00
AC	2VBS*PNL301B	N/A	PNL	120 VAC VITAL BUS	7	CTR	288.00
AC	2VBS*PNL302B	N/A	PNL	120 VAC VITAL BUS	7	CTR	288.00
AC	3-1-2ENSX04	2ENS*SWG101	HGA	TRAIN A LOAD SHED RELAY	25	CSA	261.00
AC	3-1-2ENSY04	2ENS*SWG103	HGA	TRAIN B LOAD SHED RELAY	25	CSB	261.00
AC	3-2ENSX04	2ENS*SWG101	HFA	TRAIN A LOAD SHED RELAY	25	CSA	261.00
AC	3-2ENSY04	2ENS*SWG103	HFA	TRAIN B LOAD SHED RELAY	25	CSB	261.00
AC	40-2EGPA05	2ENS*SWG101	CEH51A	RELAY	25	CSA	261.00
AC	40-2EGPB05	2ENS*SWG103	CEH51A	RELAY	25	CSB	261.00
AC	42X-2HVPA01	2CEC*PNL859	GPI	RELAY FOR 2HVR*FN1A	25	CRR	288.00
AC	42X-2HVPB01	2CEC*PNL861	GPI	RELAY FOR 2HVR*FN1B	25	CRR	288.00
AC	42X-2HVPC01	2CEC*PNL859	GPI	RELAY FOR 2HVR*FN1C	25	CRR	288.00
AC	42X-2HVPD01	2CEC*PNL861	GPI	RELAY FOR 2HVR*FN1D	25	CCR	306.00
AC	4EX1-2EGSA04	2CES*IPNL406	AGA-GPDR	2EGS*G1 CONTROL PANEL	25	DG	
AC	4EX3-2EGSA04	2CES*IPNL406	AGA-GPDR	2EGS*G1 CONTROL PANEL	25	DG	
AC	86GX1-2EGSA01	2CES*IPNL406	AGA-GPDR	2EGS*G1 CONTROL PANEL	25	DG	
AC	4X-2EGSA04	2CES*IPNL406	AGA-GPDR	2EGS*G1 CONTROL PANEL	25	DG	
AC	52T1-2EGSA01	2CES*IPNL406		2EGS*G1 CONTROL PANEL	25	DG	
AC	52C1-2EGSA01	2CES*IPNL406		2EGS*G1 CONTROL PANEL	25	DG	
AC	4EX2-2EGSA06	2CES*IPNL406	AGA-GPDR	2EGS*G1 CONTROL PANEL	25	DG	
AC	4X2-2EGSA06	2CES*IPNL406	AGA-GPDR	2EGS*G1 CONTROL PANEL	25	DG	

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
AC	48CL2-2EGSA06	2CES*IPNL406	AGA-GPDR	2EGS*G1 CONTROL PANEL	25	DG	
AC	48CL1-2EGSA01	2CES*IPNL406	AGA-GPDR	2EGS*G1 CONTROL PANEL	25	DG	
AC	14RX1-2EGSA01	2CES*IPNL406	AGA-GPDR	2EGS*G1 CONTROL PANEL	25	DG	
AC	14RX2-2EGSA06	2CES*IPNL406	AGA-GPDR	2EGS*G1 CONTROL PANEL	25	DG	
AC	52T2-2EGSA06	2CES*IPNL406		2EGS*G1 CONTROL PANEL	25	DG	
AC	52C2-2EGSA06	2CES*IPNL406		2EGS*G1 CONTROL PANEL	25	DG	
AC	13SX1-2EGSA01	2CES*IPNL406	AGA-GPDR	2EGS*G1 CONTROL PANEL	25	DG	
AC	13SX2-2EGSA06	2CES*IPNL406	AGA-GPDR	2EGS*G1 CONTROL PANEL	25	DG	
AC	14FFX1-2EGSA01	2CES*IPNL406	AGA-GPDR	2EGS*G1 CONTROL PANEL	25	DG	
AC	14FFX2-2EGSA06	2CES*IPNL406	AGA-GPDR	2EGS*G1 CONTROL PANEL	25	DG	
AC	4EY2-2EGSA05	2CES*IPNL406		2EGS*G1 CONTROL PANEL	25	DG	
AC	4EY1-2EGSA05	2CES*IPNL406		2EGS*G1 CONTROL PANEL	25	DG	
AC	4XY1-2EGSA05	2CES*IPNL406		2EGS*G1 CONTROL PANEL	25	DG	
AC	4XY2-2EGSA05	2CES*IPNL406		2EGS*G1 CONTROL PANEL	25	DG	
AC	86-2EGX01		HEA	2EGS*G1 CONTROL PANEL	25	DG	
AC	4XY-2EGSA11	2CES*IPNL407	AGA-GPDR	2EGS*G1 CONTROL PANEL	25	DG	
AC	4GEX-2EGSA11		AGA-GPDR	2EGS*G1 CONTROL PANEL	25	DG	
AC	3VRC-2EGSA11		AGA-GPDR	2EGS*G1 CONTROL PANEL	25	DG	
AC	4EX1-2EGSB04	2CES*IPNL408	AGA-GPDR	2EGS*G3 CONTROL PANEL	25	DG	
AC	4EX3-2EGSB04	2CES*IPNL408	AGA-GPDR	2EGS*G3 CONTROL PANEL	25	DG	
AC	86GX1-2EGSB01	2CES*IPNL408	AGA-GPDR	2EGS*G3 CONTROL PANEL	25	DG	
AC	4X-2EGSB04	2CES*IPNL408	AGA-GPDR	2EGS*G3 CONTROL PANEL	25	DG	
AC	52T1-2EGSB01	2CES*IPNL408		2EGS*G3 CONTROL PANEL	25	DG	
AC	52C1-2EGSB01	2CES*IPNL408		2EGS*G3 CONTROL PANEL	25	DG	
AC	4EX2-2EGSB06	2CES*IPNL408	AGA-GPDR	2EGS*G3 CONTROL PANEL	25	DG	
AC	4X2-2EGSB06	2CES*IPNL408	AGA-GPDR	2EGS*G3 CONTROL PANEL	25	DG	
AC	48CL2-2EGSB06	2CES*IPNL408	AGA-GPDR	2EGS*G3 CONTROL PANEL	25	DG	
AC	48CL1-2EGSB01	2CES*IPNL408	AGA-GPDR	2EGS*G3 CONTROL PANEL	25	DG	

Table 3.1-1B Active Components

System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
AC	14RX1-2EGSB01	2CES*IPNL408	AGA-GPDR	2EGS*G3 CONTROL PANEL	25	DG	
AC	14RX2-2EGSB06	2CES*IPNL408	AGA-GPDR	2EGS*G3 CONTROL PANEL	25	DG	
AC	52T2-2EGSB06	2CES*IPNL408		2EGS*G3 CONTROL PANEL	25	DG	
AC	52C2-2EGSB06	2CES*IPNL408		2EGS*G3 CONTROL PANEL	25	DG	
AC	13SX1-2EGSB01	2CES*IPNL408	AGA-GPDR	2EGS*G3 CONTROL PANEL	25	DG	
AC	13SX2-2EGSB06	2CES*IPNL408	AGA-GPDR	2EGS*G3 CONTROL PANEL	25	DG	
AC	14FFX1-2EGSB01	2CES*IPNL408	AGA-GPDR	2EGS*G3 CONTROL PANEL	25	DG	
AC	14FFX2-2EGSB06	2CES*IPNL408	AGA-GPDR	2EGS*G3 CONTROL PANEL	25	DG	
AC	4EY2-2EGSB05	2CES*IPNL408		2EGS*G3 CONTROL PANEL	25	DG	
AC	4EY1-2EGSB05	2CES*IPNL408		2EGS*G3 CONTROL PANEL	25	DG	
AC	4XY1-2EGSB05	2CES*IPNL408		2EGS*G3 CONTROL PANEL	25	DG	
AC	4XY2-2EGSB05	2CES*IPNL408		2EGS*G3 CONTROL PANEL	25	DG	
AC	86-2EGY01		HEA	2EGS*G3 CONTROL PANEL	25	DG	
AC	4XY-2EGSB11	2CES*IPNL412	AGA-GPDR	2EGS*G3 CONTROL PANEL	25	DG	
AC	4GEX-2EGSB11	2CES*IPNL412	AGA-GPDR	2EGS*G3 CONTROL PANEL	25	DG	
AC	3VRC-2EGSB11	2CES*IPNL412	AGA-GPDR	2EGS*G3 CONTROL PANEL	25	DG	
AC	52-2ENSX10	2ENS*SWG101-1	AUXSW	AUX SWITCH	0	CSA	261.00
AC	52-2ENSX11	2ENS*SWG101-1	AUXSW	AUX SWITCH	0	CSA	261.00
AC	52-2ENSX12	2ENS*SWG101-1	AUXSW	AUX SWITCH	0	CSA	261.00
AC	52-2ENSY10	2ENS*SWG103-4	AUXSW	AUX SWITCH	0	CSB	261.00
AC	52-2ENSY11	2ENS*SWG103-2	AUXSW	AUX SWITCH	0	CSB	261.00
AC	52-2ENSY12	2ENS*SWG103-1	AUXSW	AUX SWITCH	0	CSB	261.00
AC	62-1-2HVPA01	2CEC*PNL859	AGA (TDPU)	RELAY FOR 2HVP*FN1A	25	CRR	288.00
AC	62-1-2HVPB01	2CEC*PNL861	AGA (TDPU)	RELAY FOR 2HVP*FN1B	25	CRR	288.00
AC	62-1-2HVPC01	2CEC*PNL859	AGA (TDPU)	RELAY FOR 2HVP*FN1C	25	CRR	288.00
AC	62-1-2HVPD01	2CEC*PNL861	AGA (TDPU)	RELAY FOR 2HVP*FN1D	25	CCR	306.00
AC	62-1X-2HVPA01	2CEC*PNL859	EGPI	RELAY FOR 2HVP*FN1A	25	CRR	288.00
AC	62-1X-2HVPB01	2CEC*PNL861	EGPI	RELAY FOR 2HVP*FN1B	25	CRR	288.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
AC	62-1X-2HVPC01	2CEC*PNL859	EGPI	RELAY FOR 2HVP*FN1C	25	CRR	288.00
AC	62-1X-2HVPD01	2CEC*PNL861	EGPI	RELAY FOR 2HVP*FN1D	25	CCR	306.00
AC	62-2ENSX04	2ENS*SWG101	AGA (TDPU)	TRAIN A LOAD SHED RELAY	25	CSA	261.00
AC	62-2ENSY04	2ENS*SWG103	AGA (TDPU)	TRAIN B LOAD SHED RELAY	25	CSB	261.00
AC	62-2HVPA01	2CEC*PNL859	AGA (TDPU)	RELAY FOR 2HVP*FN1A	25	CRR	288.00
AC	62-2HVPB01	2CEC*PNL861	AGA (TDPU)	RELAY FOR 2HVP*FN1B	25	CRR	288.00
AC	62-2HVPC01	2CEC*PNL859	AGA (TDPU)	RELAY FOR 2HVP*FN1C	25	CRR	288.00
AC	62-2HVPD01	2CEC*PNL861	AGA (TDPU)	RELAY FOR 2HVP*FN1D	25	CRR	288.00
AC	71X1-2ENSX04	2ENS*SWG101	HFA	EMERGENCY SEQUENCER RELAY	25	CSA	261.00
AC	71X1-2ENSY04	2ENS*SWG103	HFA	TRAIN B LOAD SHED RELAY	25	CSB	261.00
AC	71X2-2ENSX04	2ENS*SWG101	HFA	TRAIN A LOAD SHED RELAY	25	CSA	261.00
AC	71X2-2ENSY04	2ENS*SWG103	HFA	TRAIN B LOAD SHED RELAY	25	CSB	261.00
AC	71X3-2ENSX04	2ENS*SWG101	HFA	TRAIN A LOAD SHED RELAY	25	CSA	261.00
AC	71X3-2ENSY04	2ENS*SWG103	HFA	TRAIN B LOAD SHED RELAY	25	CSB	261.00
AC	80-2HVPA01	2CEC*PNL859	GPI	RELAY FOR 2HVP*FN1A	25	CRR	288.00
AC	80-2HVPB01	2CEC*PNL861	GPI	RELAY FOR 2HVP*FN1B	25	CRR	288.00
AC	80-2HVPC01	2CEC*PNL859	GPI	RELAY FOR 2HVP*FN1C	25	CRR	288.00
AC	80-2HVPD01	2CEC*PNL871	GPI	RELAY FOR 2HVP*FN1D	25	CCR	306.00
AC	86-1-2EGPY02	2ENS*SWG103	HEA	LOCK OUT RELAY	25	CSA	261.00
AC	94-1-2ENSX04	2ENS*SWG101	HFA	RELAY	25	CSA	261.00
AC	94-1-2ENSY04	2ENS*SWG103	HFA	RELAY	25	CSA	261.00
ADS	2IAS*PI181	2CEC*PNL601	PI	PRESSURE INDICATOR	8	CCR	306.00
ADS	2IAS*PWRS181	2CEC*PNL829	PIS	PRESSURE INDICATING SWITCH		CRR	288.00
ADS	2IAS*PT181	LOCAL	PT	PRESSURE TRANSMITTER (ADS HEADER "A" PRESSURE)	8	SC	293.00
ADS	2IAS*SOV164	LOCAL	SOV	INSTR AIR CONTMT ISOL SOV	15	SC	294.00
ADS	2IAS*SOV165	LOCAL	SOV	INSTR AIR CONTMT ISOL SOV	15	SC	294.00
ADS	2IAS*SOV166	LOCAL	SOV	INSTR AIR CONTMT ISOL SOV	15	SC	294.00

Table 3.1-1B Active Components

System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
ADS	2IAS*SOV184	LOCAL	SOV	INSTR AIR CONTMT ISOL SOV	15	PC	294.00
ADS	2IAS*SOVX181	LOCAL	SOV	ADS HEADER A PRESSURE, SOV	15	SC	294.00
ADS	2IAS*SOVX186	LOCAL	SOV	ADS HEADER B PRESSURE, SOV	15	SC	296.00
ADS	2IAS*SOVY181	LOCAL	SOV	ADS HEADER A PRESSURE, SOV	15	SC	294.00
ADS	2IAS*SOVY186	LOCAL	SOV	ADS HEADER B PRESSURE, SOV	15	SC	296.00
ADS	2IAS*SV19A	LOCAL	SV	2IAS*TK4 ADS RELIEF VALVE	13	SC	289.00
ADS	2IAS*SV19B	LOCAL	SV	2IAS*TK5 ADS RELIEF VALVE	13	SC	289.00
ADS	2IAS*SV20A	LOCAL	SV	2IAS*TK4 ADS RELIEF VALVE	13	SC	289.00
ADS	2IAS*SV20B	LOCAL	SV	2IAS*TK5 ADS RELIEF VALVE	13	SC	294.00
ADS	2IAS*TK32	LOCAL	TK	ADS VALVE ACCUMULATOR	19	PC	289.00
ADS	2IAS*TK33	LOCAL	TK	ADS VALVE ACCUMULATOR	19	PC	289.00
ADS	2IAS*TK34	LOCAL	TK	ADS VALVE ACCUMULATOR	19	PC	289.00
ADS	2IAS*TK35	LOCAL	TK	ADS VALVE ACCUMULATOR	19	PC	289.00
ADS	2IAS*TK36	LOCAL	TK	ADS VALVE ACCUMULATOR	19	PC	289.00
ADS	2IAS*TK37	LOCAL	TK	ADS VALVE ACCUMULATOR	19	PC	289.00
ADS	2IAS*TK38	LOCAL	TK	ADS VALVE ACCUMULATOR	19	PC	289.00
ADS	2IAS*TK4	LOCAL	TK	ADS ACCUM AIR RECEIVER	19	SC	289.00
ADS	2IAS*TK5	LOCAL	TK	ADS ACCUM AIR RECEIVER	19	SC	289.00
ADS	2IAS-FLT9	LOCAL	FLT	FILTER IN AIR LINE TO ADS	20	SC	289.00
ADS	2MSS*PSV121	LOCAL	PSV	SAFETY/RELIEF VALVE	14	PC	297.00
ADS	2MSS*PSV126	LOCAL	PSV	SAFETY/RELIEF VALVE	14	PC	297.00
ADS	2MSS*PSV127	LOCAL	PSV	SAFETY/RELIEF VALVE	14	PC	297.00
ADS	2MSS*PSV129	LOCAL	PSV	SAFETY/RELIEF VALVE	14	PC	297.00
ADS	2MSS*PSV130	LOCAL	PSV	SAFETY/RELIEF VALVE	14	PC	297.00
ADS	2MSS*PSV134	LOCAL	PSV	SAFETY/RELIEF VALVE	14	PC	297.00
ADS	2MSS*PSV137	LOCAL	PSV	SAFETY/RELIEF VALVE	14	PC	296.00
ADS	2MSS*SOV121A	LOCAL	SOV	SAFETY/RELIEF VALVE	15	PC	296.00
ADS	2MSS*SOV121B	LOCAL	SOV	SAFETY/RELIEF VALVE	15	PC	296.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
ADS	2MSS*SOV126A	LOCAL	SOV	SAFETY/RELIEF VALVE	15	PC	297.00
ADS	2MSS*SOV126B	LOCAL	SOV	SAFETY/RELIEF VALVE	15	PC	297.00
ADS	2MSS*SOV127A	LOCAL	SOV	SAFETY/RELIEF VALVE	15	PC	297.00
ADS	2MSS*SOV127B	LOCAL	SOV	SAFETY/RELIEF VALVE	15	PC	297.00
ADS	2MSS*SOV129A	LOCAL	SOV	SAFETY/RELIEF VALVE	15	PC	297.00
ADS	2MSS*SOV129B	LOCAL	SOV	SAFETY/RELIEF VALVE	15	PC	297.00
ADS	2MSS*SOV130A	LOCAL	SOV	SAFETY/RELIEF VALVE	15	PC	297.00
ADS	2MSS*SOV130B	LOCAL	SOV	SAFETY/RELIEF VALVE	15	PC	297.00
ADS	2MSS*SOV134A	LOCAL	SOV	SAFETY/RELIEF VALVE	15	PC	297.00
ADS	2MSS*SOV134B	LOCAL	SOV	SAFETY/RELIEF VALVE	15	PC	297.00
ADS	2MSS*SOV137A	LOCAL	SOV	SAFETY/RELIEF VALVE	15	PC	296.00
ADS	2MSS*SOV137B	LOCAL	SOV	SAFETY/RELIEF VALVE	15	PC	296.00
ADS	B22C-K12A	2CEC*PNL628	AGA-GP	RPV LEVEL 3 SIGNAL RELAY	25	CB	306.00
ADS	B22C-K12B	2CEC*PNL631	AGA-GP	RPV LEVEL 3 SIGNAL RELAY	25	CB	306.00
ADS	B22C-K13A	2CEC*PNL628	AGA-GP	LPCS/LPCI PUMP RUNNING RELAY	25	CB	306.00
ADS	B22C-K13B	2CEC*PNL631	AGA-GP	LPCS/LPCI PUMP RUNNING RELAY	25	CB	306.00
ADS	B22C-K14A	2CEC*PNL628	AGA-GP	LPCS/LPCI PUMP RUNNING RELAY	25	CB	306.00
ADS	B22C-K14B	2CEC*PNL631	AGA-GP	LPCS/LPCI PUMP RUNNING RELAY	25	CB	306.00
ADS	B22C-K5A	2CEC*PNL628	AGA-TR	ADS TIMING RELAY	25	CB	306.00
ADS	B22C-K5B	2CEC*PNL631	AGA-TR	ADS TIMING RELAY	25	CB	306.00
ADS	B22C-K6A	2CEC*PNL628	AGA-GP	ADS CHANNEL ACTUATION RELAY	25	CB	306.00
ADS	B22C-K6B	2CEC*PNL631	AGA-GP	ADS CHANNEL ACTUATION RELAY	25	CB	306.00
ADS	B22C-K6E	2CEC*PNL628	AGA-GP	ADS CHANNEL ACTUATION RELAY	25	CB	306.00
ADS	B22C-K6F	2CEC*PNL631	AGA-GP	ADS CHANNEL ACTUATION RELAY	25	CB	306.00
ADS	B22C-K70A	2CEC*PNL628	AGA-GP	LPCS/LPCI PUMP RUNNING RELAY	25	CB	306.00
ADS	B22C-K70B	2CEC*PNL631	AGA-GP	LPCS/LPCI PUMP RUNNING RELAY	25	CB	306.00
ADS	B22C-K8A	2CEC*PNL628	AGA-GP	ADS SEAL IN RELAY	25	CB	306.00
ADS	B22C-K8B	2CEC*PNL631	AGA-GP	ADS SEAL IN RELAY	25	CB	306.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
ADS	B22C-K8E	2CEC*PNL628	AGA-GP	ADS SEAL IN RELAY	25	CB	306.00
ADS	B22C-K8F	2CEC*PNL631	AGA-GP	ADS SEAL IN RELAY	25	CB	306.00
ADS	B22C-K9A	2CEC*PNL628	AGA-GP	ADS SEAL IN RELAY	25	CB	306.00
ADS	B22C-K9B	2CEC*PNL631	AGA-GP	ADS SEAL IN RELAY	25	CB	306.00
ADS	2CEC*PNL628		PNL	ADS/LPCI Relay Panel	5	CB	306.00
ADS	2CEC*PNL631		PNL	ADS/LPCI Relay Panel	5	CB	306.00
PCV	2CPS*AOV109	LOCAL	AOV	SUPPR DISCH INBD ISOL V	13	PC	218.00
PCV	2CPS*SOV109	LOCAL	SOV	SUPPR DISCH INBD ISOL V	15	PC	218.00
PCV	2CPS*SOV133	LOCAL	SOV	2CPS*AOV109 N2 SPLY ISOL V	15	SC	217.00
DC	27X1-2ENSXO4	2ENS*SWG101	HFA	TRAIN A LOAD SHED RELAY	25	CSA	261.00
DC	27X1-2ENSYO4	2ENS*SWG103	HFA	TRAIN B LOAD SHED RELAY	25	CSB	261.00
DC	27X2-2ENSX04	2ENS*SWG101	HFA	TRAIN A LOAD SHED RELAY	25	CSA	261.00
DC	27X2-2ENSY04	2ENS*SWG103	HFA	TRAIN B LOAD SHED RELAY	25	CSB	261.00
DC	27X4-2ENSX04	2ENS*SWG101	HFA	TRAIN A LOAD SHED RELAY	25	CSA	261.00
DC	27X4-2ENSY04	2ENS*SWG103	HFA	TRAIN B LOAD SHED RELAY	25	CSB	261.00
DC	2A-2ENSX04	2ENS*SWG101	AGA (TDPU)	TRAIN A LOAD SHED RELAY	25	CSA	261.00
DC	2A-2ENSY04	2ENS*SWG103	AGA (TDPU)	TRAIN B LOAD SHED RELAY	25	CSB	261.00
DC	2B-2ENSX04	2ENS*SWG101	AGA (TDPU)	TRAIN A LOAD SHED RELAY	25	CSA	261.00
DC	2B-2ENSY04	2ENS*SWG103	AGA (TDPU)	TRAIN B LOAD SHED RELAY	25	CSB	261.00
DC	2BYS*BAT2A	LOCAL	BAT	125V DC BAT.2A DIV I	2	CBR	261.00
DC	2BYS*BAT2B	LOCAL	BAT	125V DC EMER. BAT DIV II	2	CBR	261.00
DC	2BYS*CHGR2A1	LOCAL	CHGR	125V BAT CHGR DIV I	3	CSA	261.00
DC	2BYS*CHGR2A2	LOCAL	CHGR	125V BAT CHGR STANDBY DIV I	3	CSA	261.00
DC	2BYS*CHGR2B1	LOCAL	CHGR	125V BAT CHGR.	3	CSB	261.00
DC	2BYS*CHGR2B2	LOCAL	CHGR	125V BAT. CHGR. STAND BY DIV.	3	CSB	261.00
DC	2BYS*PNL201A	N/A	PNL	125 VDC PANEL	7	CTR	288.00
DC	2BYS*PNL201B	N/A	PNL	125 VDC PANEL	7	CTR	288.00
DC	2BYS*PNL202A	N/A	PNL	125 VDC PANEL	7	CTR	288.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
DC	2BYS*PNL202B	N/A	PNL	125 VDC PANEL	7	CTR	288.00
DC	2BYS*PNL204A	N/A	PNL	DIESEL GENERATOR CONTROL	7	DG	261.00
DC	2BYS*PNL204B	N/A	PNL	125 VDC PANEL	7	DG	261.00
DC	2BYS*SWG002A	N/A	SWG	DIVISION I 125 VDC SWITCHGEAR	1	DG	261.00
DC	2BYS*SWG002A-1B	N/A	ACB	BREAKER 125VDC SUPPLY TO : 2BYS*BAT2A	0	CSA	261.00
DC	2BYS*SWG002A-2B	N/A	ACB	125VDC SUPPLY TO :	0	CSA	261.00
DC	2BYS*SWG002B	N/A	SWG	DIVISION II 125VDC SWITCHGEAR	1	CSB	261.00
DC	2BYS*SWG002B-1B	N/A	ACB	BREAKER 125VDC SUPPLY TO : 2BYS*BAT2B	0	CSB	261.00
DC	2BYS*SWG002B-2B	N/A	ACB	BREAKER 125VDC SUPPLY FROM : 2BYS*CHGR2B1 , 2B2	0	CSB	261.00
DC	2DMS*MCCA1	N/A	MCC	125V DC MCC	1	ABN	240.00
DC	2DMS*MCCB1	N/A	MCC	DC POWER PANEL	1	ABS	240.00
DC	2EJS*PNL100A-1	N/A	ACB	CIRCUIT BREAKER FOR POWER TO 2BYS*CHGR2A2	0	CSA	261.00
DC	2EJS*PNL300B-1	N/A	ACB	CIRCUIT BREAKER FOR POWER TO 2BYS*CHGR2B2	0	CSB	261.00
DC	2LAC*PNL100A-1	N/A	ACB	POWER TO : 2LAC*XLE01	0	CSA	261.00
DC	2LAC*PNL300B-1	N/A	ACB	POWER TO : 2LAC*XLE02	0	CSB	261.00
DC	DR-2ENSX04	2ENS*SWG101	HFA	TRAIN A LOAD SHED RELAY	25	CSA	261.00
DC	DR-2ENSY04	2ENS*SWG103	HFA	TRAIN B LOAD SHED RELAY	25	CSB	261.00
ECCS	2ISC*LIS1691B	2CEC*PNL618	LIS	RPV LOW LEVEL SWITCH		CB	306.00
ECCS	2ISC*LIS1691A	2CEC*PNL629	LIS	RPV LOW LEVEL SWITCH		CB	306.00
ECCS	2ISC*LIS1691E	2CEC*PNL629	LIS	RPV LOW LEVEL SWITCH		CB	306.00
ECCS	2ISC*LIS1691F	2CEC*PNL618	LIS	RPV LOW LEVEL SWITCH		CB	306.00
ECCS	2ISC*PIS1694A	2CEC*PNL629	PIS	HIGH DRYWELL PRESSURE SWITCH		CCR	306.00
ECCS	2ISC*PIS1694B	2CEC*PNL629	PIS	HIGH DRYWELL PRESSURE SWITCH		CCR	306.00
ECCS	2ISC*PIS1694E	2CEC*PNL629	PIS	HIGH DRYWELL PRESSURE SWITCH		CCR	306.00
ECCS	2ISC*PIS1694F	2CEC*PNL618	PIS	HIGH DRYWELL PRESSURE		CCR	306.00

Table 3.1-1B Active Components

System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
ECCS	2ISC*LT9A	2CES*RAK004	LT	DIFF. PRESSURE TRANSMITTER		SC	261.00
ECCS	2ISC*LT9B	2CES*RAK027	LT	DIFF. PRESSURE TRANSMITTER		SC	261.00
ECCS	2ISC*LT9C	2CES*RAK004	LT	DIFF. PRESSURE TRANSMITTER		SC	261.00
ECCS	2ISC*LT9D	2CES*RAK027	LT	DIFF. PRESSURE TRANSMITTER		SC	261.00
ECCS	2ISC*PT17A	2CES*RAK004	PT	PRESSURE TRANSMITTER		SC	261.00
ECCS	2ISC*PT17B	2CES*RAK027	PT	PRESSURE TRANSMITTER		SC	261.00
ECCS	2ISC*PT17C	2CES*RAK004	PT	PRESSURE TRANSMITTER		SC	261.00
ECCS	2ISC*PT17D	2CES*RAK027	PT	PRESSURE TRANSMITTER		SC	261.00
ECCS	E12A-K110A	2CEC*PNL629	GE/HFA	LPCS PUMP START RELAY	25	CCR	306.00
ECCS	E12A-K110B	2CEC*PNL629	HFA	LPCI PUMP B, C START RELAY	25	CCR	306.00
ECCS	E12A-K126A	2CEC*PNL629	AGA	LOCA SIGNAL TO SEQUENCE	25	CB	306.00
ECCS	E12A-K5	2CEC*PNL618	AGA	HI DRYWELL PRESSURE SIGNAL RELAY	25	CB	306.00
ECCS	E12A-K6	2CEC*PNL618	AGA	HI DRYWELL PRESSURE SIGNAL RELAY	25	CB	306.00
ECCS	E12A-K7	2CEC*PNL618	AGA	LOW DRYWELL PRESSURE SIGNAL RELAY	25	CB	306.00
ECCS	E12A-K8	2CEC*PNL618	AGA	LOW DRYWELL PRESSURE SIGNAL RELAY	25	CB	306.00
ECCS	E12A-K9B	2CEC*PNL618	AGA	LPCI "B" - AUX RELAY	25	CB	306.00
ECCS	E21A-126B	2CEC*PNL618	AGA	LOCA SIGNAL RELAY TO SEQUENCER	25	CB	306.00
ECCS	E21A-K11	2CEC*PNL629	AGA	LPCS INITIATION SIGNAL RELAY	25	CB	306.00
ECCS	E21A-K81	2CEC*PNL629	AGA	CHANNEL RELAY - LOW RPV LEVEL SIGNAL	25	CB	306.00
ECCS	E21A-K84	2CEC*PNL629	AGA	CHANNEL TRIP RELAY HIGH DRYWELL PRESSURE	25	CB	306.00
ECCS	E21A-K91	2CEC*PNL629	AGA	CHANNEL TRIP RELAY - LOW RPV LEVEL	25	CB	306.00
ECCS	E21A-K94	2CEC*PNL629	AGA	CHANNEL TRIP RELAY HIGH DRYWELL PRESSURE	25	CB	306.00
HPCS	27X1-2ENSC10	2ENS*SWG102	AGA-TR	HPCS START RELAY	25	DG	261.00
HPCS	27X2-2ENSC10	2ENS*SWG102	AGA-TR	HPCS START RELAY	25	DG	261.00
HPCS	2BYS*BAT2C	LOCAL	BAT	EMERGENCY DC DISTRIBUTION 125 VDC BATTERY DIV 3	2	CSH	261.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
HPCS	2BYS*CHGR2C1	LOCAL	CHGR	EMERGENCY DC DISTRIBUTION 125V BATTERY CHGR	3	CSH	261.00
HPCS	2BYS*CHGR2C2	LOCAL	CHGR	EMERGENCY DC DISTRIBUTION 125V BATTERY CHGR	3	CSH	261.00
HPCS	2CES*IPNL413	N/A	PNL	HPCS DC POWER PANEL	5	DG	261.00
HPCS	2CES*IPNL414	N/A	PNL	HPCS DC POWER PANEL	5	DG	261.00
HPCS	2CSH*LS123	2CEC*PNL625	LIS	LEVEL SWITCH		CCR	306.00
HPCS	2CSH*LS124	2CEC*PNL625	LIS	LEVEL SWITCH		CCR	306.00
HPCS	2CSH*LS3A	2CEC*PNL625	LIS	LEVEL SWITCH		CCR	306.00
HPCS	2CSH*LS3B	2CEC*PNL625	LIS	LEVEL SWITCH		CCR	306.00
HPCS	2CSH*FE105	LOCAL	FE	FLOW ELEMENT (2CSH*P1 DISCHARGE)	8	SC	188.00
HPCS	2CSH*LT123	LOCAL	LT	SUP POOL LEVEL TRANSMITTER	8	SC	306.00
HPCS	2CSH*LT124	LOCAL	LT	SUP POOL LEVEL TRANSMITTER	8	SC	306.00
HPCS	2CSH*LT3A	LOCAL	LS	COND STORAGE TK LEVEL TRANSMITTER	8	PT	306.00
HPCS	2CSH*LT3B	LOCAL	LS	COND STORAGE TK LEVEL TRANSMITTER	8	PT	306.00
HPCS	2CSH*MOV101	LOCAL	MOV	MOTOR OPERATED VALVE	14	SC	177.00
HPCS	2CSH*MOV105	LOCAL	MOV	MOTOR OPERATED VALVE	14	SC	218.00
HPCS	2CSH*MOV107	LOCAL	MOV	MOTOR OPERATED VALVE	14	SC	292.00
HPCS	2CSH*MOV118	LOCAL	MOV	MOTOR OPERATED VALVE	14	SC	195.00
HPCS	2CSH*P1	LOCAL	P	H.P.C.S. PUMP	12	SC	178.00
HPCS	2CSH*PSL102	2CEC*PNL625	PSL	PRESSURE INDICATING SWITCH-LOW (HPCS 2CSH*P1 SUCTION PRESSURE)		CCR	306.00
HPCS	2CSH*PT102	LOCAL	PT	PRESSURE TRANSMITTER (HPCS 2CSH*P1 SUCTION PRESSURE)	8	SC	175.00
HPCS	2CSH*STRT1	LOCAL	STRT	TEMPORARY STRAINER	20	SC	178.00
HPCS	2EGF*P2A	LOCAL	P	FUEL OIL TRANSFER PUMP	11	DG	261.00
HPCS	2EGF*P2B	LOCAL	P	FUEL OIL TRANSFER PUMP	11	DG	261.00
HPCS	2EGS*EG2	LOCAL	EG	DIESEL GENERATOR 2	9	DG	261.00
HPCS	2EHS*MCC201	N/A	MCC	600 VAC MCC	1	CSH	261.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
HPCS	2EHS*MCC201-4B	N/A	ACB	EMERGENCY DC DISTRIBUTION AC FEED FOR 2BYS*CHGR2C1 CABLE NO 2BYSNPL001	0	CSH	261.00
HPCS	2EHS*MCC201-5C	N/A	ACB	EMERGENCY DC DISTRIBUTION AC FEED FOR 2BYS*CHGR2C2 CABLE NO 2BYSNPL002	0	CSH	261.00
HPCS	2EJS*X2	LOCAL	X	4160/600V HPCS XFMR	4	CSH	261.00
HPCS	2ENS*SWG102	N/A	SWG	4.16 KV BUS	1	CSH	261.00
HPCS	2ENS*SWG102-1	N/A	ACB	CIRCUIT BREAKER FOR 2NNS-SWG016-2	0	CSH	261.00
HPCS	2ENS*SWG102-2	N/A	ACB	HPCS PUMP BREAKER	0	CSH	261.00
HPCS	2ENS*SWG102-4	N/A	ACB	CIRCUIT BREAKER FOR 2NNS-SWG017-2	0	CSH	261.00
HPCS	2ENS*SWG102-5	N/A	ACB	RESERVE POWER SUPPLY BREAKER	0	CSH	261.00
HPCS	2ENS*SWG102-6	N/A	ACB	CIRCUIT BREAKER FOR 2EGS*EG2	0	CSH	261.00
HPCS	2HVP*AOD5A	LOCAL	AOD	INLET DMPR	13	DG	284.00
HPCS	2HVP*AOD5B	LOCAL	AOD	INLET DMPR	13	DG	284.00
HPCS	2HVP*FN2A	LOCAL	FN	AXIAL FAN - DG	17	DG	275.00
HPCS	2HVP*FN2B	LOCAL	FN	AXIAL FAN - DG	17	DG	275.00
HPCS	2HVP*FS9A	LOCAL	FS	FLOW SWITCH	8	DG	280.00
HPCS	2HVP*FS9B	LOCAL	FS	FLOW SWITCH	8	DG	280.00
HPCS	2HVP*MOD2A	LOCAL	MOD	MOTOR OPERATED DAMPER	14	DG	279.00
HPCS	2HVP*MOD2B	LOCAL	MOD	MOTOR OPERATED DAMPER	14	DG	279.00
HPCS	2HVP*UC2	LOCAL	UC	DIESEL GENERATOR UNIT CLR	18	DG	280.00
HPCS	2HVR*TIS24A	LOCAL	TIS	TEMPERATURE SWITCH FOR UC403A	8	SC	180.00
HPCS	2HVR*TIS24B	LOCAL	TIS	TEMPERATURE SWITCH FOR UC403B	8	SC	180.00
HPCS	2HVR*UC403A	LOCAL	UC	HPCS PUMP PM UNIT COOLER	18	SC	176.00
HPCS	2HVR*UC403B	LOCAL	UC	HPCS PUMP PM UNIT COOLER	18	SC	203.00
HPCS	2ICS*PIS1667L	2CEC*PNL625	PIS	P.T. 16A P.I. SWITCH		CCR	306.00
HPCS	2ISC*LIS1673C	2CEC*PNL625	LIS	ELECTRONIC LEVEL INDICATING SWITCH ACTUATES ON LOW LEVEL.		CCR	306.00
HPCS	2ISC*LIS1673G	2CEC*PNL625	LIS	ELECTRONIC LEVEL INDICATING SWITCH ACTUATES ON LOW LEVEL.		CCR	306.00

Table 3.1-1B Active Components

System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
HPCS	2ISC*LIS1673L	2CEC*PNL625	LIS	ELECTRONIC LEVEL INDICATING SWITCH ACTUATES ON LOW LEVEL.		CCR	306.00
HPCS	2ISC*LIS1673R	2CEC*PNL625	LIS	ELECTRONIC LEVEL INDICATING SWITCH ACTUATES ON LOW LEVEL.		CCR	306.00
HPCS	2ISC*LT10A	2CES*RAK026	LT	LEVEL TRANSMITTER		SC	261.00
HPCS	2ISC*LT10B	2CES*RAK005	LT	LEVEL TRANSMITTER		SC	261.00
HPCS	2ISC*LT10C	2CES*RAK026	LT	LEVEL TRANSMITTER		SC	261.00
HPCS	2ISC*LT10D	2CES*RAK005	LT	LEVEL TRANSMITTER		SC	261.00
HPCS	2ISC*PIS1667C	2CEC*PNL625	PIS	MASTER TRIP UNIT,ACTUATES ON HIGH DRYWELL PRESSURE		CCR	306.00
HPCS	2ISC*PIS1667G	2CEC*PNL625	PIS	PRESSURE INDICATING SWITCH , MONITORS DRYWELL PRESSURE		CCR	306.00
HPCS	2ISC*PIS1667L	2CEC*PNL625	PIS	ELECTRONIC MASTER TRIP UNIT,ACTUATES ON HIGH DRYWELL PRESSURE TO ENERGIZE COMPUTER & ANNUNCIATOR ALARM		CCR	306.00
HPCS	2ISC*PIS1667R	2CEC*PNL625	PIS	ELECTRONIC MASTER TRIP UNIT,ACTUATES ON HIGH DRYWELL PRESSURE TO ENERGIZE COMPUTER & ANNUNCIATOR ALARM		CCR	306.00
HPCS	2ISC*PT16A	2CES*RAK026	PT	PRESSURE TRANSMITTER		SC	261.00
HPCS	2ISC*PT16B	2CES*RAK005	PT	PRESSURE TRANSMITTER		SC	261.00
HPCS	2ISC*PT16C	2CES*RAK026	PT	PRESSURE TRANSMITTER		SC	261.00
HPCS	2ISC*PT16D	2CES*RAK005	PT	PRESSURE TRANSMITTER		SC	261.00
HPCS	2SCV*PNL200P	N/A	PNL	120 VAC PANEL	7	DG	280.00
HPCS	2SWP*MOV15A	LOCAL	MOV	MOTOR OPERATED GATE VALVE TO UC403A	14	SC	197.00
HPCS	2SWP*MOV15B	LOCAL	MOV	GATE VALVE - MOTOR OPERATED TO UC403B	14	SC	197.00
HPCS	2SWP*MOV94A	LOCAL	MOV	MOV, SWP FROM CLR 2EGS*EG2	14	DG	271.00
HPCS	2SWP*MOV94B	LOCAL	MOV	MOV, SWP FROM CLR 2EGS*EG2	14	DG	269.00
HPCS	2SWP*MOV95A	LOCAL	MOV	MOV, SWP TO CLR 2EGS*EG2	14	DG	263.00
HPCS	2SWP*MOV95B	LOCAL	MOV	MOV, SWP TO CLR 2EGS*EG2	14	DG	263.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
HPCS	3-2EGSC01	2CES*IPNL413		RELAY FOR 2HVP*FN2A	25	DG	261.00
HPCS	3-8-2HVRA90	2CEC*PNL874	MDR	RELAY FOR 2HVR*UC403A	25	CRR	288.00
HPCS	3-8-2HVRB90	2CEC*PNL871	MDR	RELAY FOR 2HVR*UC403B	25	CCR	306.00
HPCS	42X-2HVPA02	2CEC*PNL871	GPI	RELAY FOR 2HVR*FN2A	25	CCR	306.00
HPCS	42X-2HVPB02	2CEC*PNL871	GPI	RELAY FOR 2HVR*FN2B	25	CCR	306.00
HPCS	62-1-2HVPA02	2CEC*PNL871	AGA (TDPU)	RELAY FOR 2HVP*FN2A	25	CCR	306.00
HPCS	62-1-2HVPB02	2CEC*PNL871	AGA (TDPU)	RELAY FOR 2HVP*FN2B	25	CCR	306.00
HPCS	62-1X-2HVPA02	2CEC*PNL871	EGPI	RELAY FOR 2HVP*FN2A	25	CCR	306.00
HPCS	62-1X-2HVPB02	2CEC*PNL871	EGPI	RELAY FOR 2HVP*FN2B	25	CCR	306.00
HPCS	62-2HVPA02	2CEC*PNL871	AGA (TDPU)	RELAY FOR 2HVP*FN2A	25	CCR	306.00
HPCS	62-2HVPB02	2CEC*PNL871	AGA (TDPU)	RELAY FOR 2HVP*FN2B	25	CCR	306.00
HPCS	80-2HVPA02	2CEC*PNL871	GPI	RELAY FOR 2HVP*FN2A	25	CCR	306.00
HPCS	80-2HVPB02	2CEC*PNL871	GPI	RELAY FOR 2HVP*FN2B	25	CCR	306.00
HPCS	86NA-2ENSZ02	2ENS*SWG102		4160 EMER SWGR 102 (HPCS)		CSH	261.00
HPCS	86NB-2ENSZ02	2ENS*SWG102		4160 EMER SWGR 102 (HPCS)		CSH	261.00
HPCS	K55	2ENS*SWG102		4160 EMER SWGR 102 (HPCS)		CSH	261.00
HPCS	27X1-2ENSC11	2ENS*SWG102		4160 EMER SWGR 102 (HPCS)		CSH	261.00
HPCS	62-1-2ENSC11	2ENS*SWG102		4160 EMER SWGR 102 (HPCS)		CSH	261.00
HPCS	62-2-2ENSC12	2ENS*SWG102		4160 EMER SWGR 102 (HPCS)		CSH	261.00
HPCS	27AX-2ENSC11	2ENS*SWG102		4160 EMER SWGR 102 (HPCS)		CSH	261.00
HPCS	27BX-2ENSC12	2ENS*SWG102		4160 EMER SWGR 102 (HPCS)		CSH	261.00
HPCS	27AY-2ENSC11	2ENS*SWG102		4160 EMER SWGR 102 (HPCS)		CSH	261.00
HPCS	27BY-2ENSC12	2ENS*SWG102		4160 EMER SWGR 102 (HPCS)		CSH	261.00
HPCS	27AZ-2ENSC11	2ENS*SWG102		4160 EMER SWGR 102 (HPCS)		CSH	261.00
HPCS	27BZ-2ENSC12	2ENS*SWG102		4160 EMER SWGR 102 (HPCS)		CSH	261.00
HPCS	27AA-2EGPC19	2ENS*SWG102		4160 EMER SWGR 102 (HPCS)		CSH	261.00
HPCS	27BB-2EGPC19	2ENS*SWG102		4160 EMER SWGR 102 (HPCS)		CSH	261.00
HPCS	27AC-2EGPC19	2ENS*SWG102		4160 EMER SWGR 102 (HPCS)		CSH	261.00

Table 3.1-1B Active Components

System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
HPCS	27BA-2EGPC19	2ENS*SWG102		4160 EMER SWGR 102 (HPCS)		CSH	261.00
HPCS	27BC-2EGPC19	2ENS*SWG102		4160 EMER SWGR 102 (HPCS)		CSH	261.00
HPCS	E22A-K103	2CEC*PNL625	AGA-GP	HPCS START RELAY	25	CCR	306.00
HPCS	E22A-K109	2CEC*PNL625	AGA-GP	HPCS START RELAY	25	CCR	306.00
HPCS	E22A-K11	2CEC*PNL625	AGA-GP	LOW RPV WATER LEVEL TRAIN ACTUATION RELAY	25	CCR	306.00
HPCS	E22A-K111	2CEC*PNL625	AGA-TR	LOW CST LEVEL TIME DELAY RELAY	25	CCR	306.00
HPCS	E22A-K29	2CEC*PNL625	GPI	HIGH DRYWELL PRESSURE TRAIN ACTUATION RELAY	25	CCR	306.00
HPCS	E22A-K3	2CEC*PNL625	AGA-TR	HPCS RELAY	25	CCR	306.00
HPCS	E22A-K31	2CEC*PNL625	AGA-GP	OPEN SIGNAL RELAY FOR 2CSH*MOV118	25	CCR	306.00
HPCS	E22A-K51	2CEC*PNL625	AGA-GP	PRESSURE PERMISSIVE RELAY FOR MIN FLOW	25	CCR	306.00
HPCS	E22A-K54	2CEC*PNL625	AGA-GP	LOW CST LEVEL SIGNAL RELAY	25	CCR	306.00
HPCS	E22A-K55	2CEC*PNL625	AGA-GP	HIGH LEVEL SUPPRESSION POOL RELAY	25	CCR	306.00
HPCS	E22A-K56	2CEC*PNL625	AGA-GP	FLOW PERMISSIVE RELAY FOR MIN FLOW	25	CCR	306.00
HPCS	E22A-K67	2CEC*PNL625	AGA-GP	HIGH DRYWELL PRESSURE SIGNAL RELAY	25	CCR	306.00
HPCS	E22A-K73	2CEC*PNL625	AGA-GP	HIGH WATER LEVEL SIGNAL RELAY	25	CCR	306.00
HPCS	E22A-K77	2CEC*PNL625	AGA-GP	HIGH DRYWELL PRESSURE RELAY	25	CCR	306.00
HPCS	E22A-K83	2CEC*PNL625	AGA-GP	LOW RPV WATER LEVEL RELAY	25	CCR	306.00
HPCS	E22A-K87	2CEC*PNL625	AGA-GP	HIGH DRYWELL PRESSURE SIGNAL RELAY	25	CCR	306.00
HPCS	E22A-K9	2CEC*PNL625	AGA-GP	HPCS INITIATION RELAY	25	CCR	306.00
HPCS	E22A-K93	2CEC*PNL625	AGA-GP	LOW RPV WATER LEVEL SIGNAL RELAY	25	CCR	306.00
HPCS	E22A-K97	2CEC*PNL625	AGA-GP	HIGH DRYWELL PRESSURE SIGNAL RELAY	25	CCR	306.00
HPCS	E22B-K1	2EGS*PNL028	AGA-GP	HPCS RELAY	25	CSH	261.00
HPCS	E22B-K36	2EGS*PNL028	AGA-GP	HPCS RELAY	25	CSH	261.00
HPCS	2CEC*PNL625	N/A	PNL	HPCS Relay Panel	5	CCR	306.00
HPCS	K1-945E400	2CES*IPNL413		PILOT		CSH	261.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
HPCS	K2-945E400	2CES*IPNL413		GOVERNOR & REGULATOR RESET		CSH	261.00
HPCS	K3-945E400	2CES*IPNL413		VOLTAGE RAISE		CSH	261.00
HPCS	K4-945E400	2CES*IPNL413		VOLTAGE LOWER		CSH	261.00
HPCS	K16-945E400	2CES*IPNL413		INDICATING UNIT CRANKING		CSH	261.00
HPCS	K38-945E400	2CES*IPNL413		CRANK JOG DELAY		CSH	261.00
HPCS	K32-945E400	2CES*IPNL413		FIELD FLASH TIME DELAY		CSH	261.00
HPCS	K33-945E400	2CES*IPNL413		SAFETY SETUP TIME DELAY		CSH	261.00
HPCS	K35-945E400	2CES*IPNL413		35 RPM AUXILIARY		CSH	261.00
HPCS	K9-945E400	2CES*IPNL413		OVER CRANK AUXILIARY		CSH	261.00
HPCS	K10-945E400	2CES*IPNL413		OVERSPEED AUXILIARY		CSH	261.00
HPCS	K11-945E400	2CES*IPNL413		LOW OIL PRESS SHUTDOWN AUXILIARY		CSH	261.00
HPCS	K12-945E400	2CES*IPNL413		HIGH WATER TEMP SHUTDOWN AUXILIARY		CSH	261.00
HPCS	K55-945E400	2CES*IPNL413		SPEED SENSING AUXILIARY		CSH	261.00
HVAC	2HVR*TIS16A	LOCAL	TIS	TEMPERATURE SWITCH FOR UC409A	8	ABS	256.00
HVAC	2HVR*TIS16B	LOCAL	TIS	TEMPERATURE SWITCH FOR UC409B	8	ABS	256.00
HVAC	2HVR*TIS19A	LOCAL	TIS	TEMPERATURE SWITCH FOR UC408A	8	ABN	245.00
HVAC	2HVR*TIS19B	LOCAL	TIS	TEMPERATURE SWITCH FOR UC408B	8	ABN	256.00
HVAC	2HVR*TIS22A	LOCAL	TIS	TEMPERATURE SWITCH FOR UC402A	8	ABN	180.00
HVAC	2HVR*TIS22B	LOCAL	TIS	TEMPERATURE SWITCH FOR UC402B	8	ABN	180.00
HVAC	2HVR*TIS23A	LOCAL	TIS	TEMPERATURE SWITCH FOR UC401A	8	ABN	190.00
HVAC	2HVR*TIS23B	LOCAL	TIS	TEMPERATURE SWITCH FOR UC401B	8	ABS	185.00
HVAC	2HVR*TIS23C	LOCAL	TIS	TEMPERATURE SWITCH FOR UC401C	8	ABS	180.00
HVAC	2HVR*TIS23D	LOCAL	TIS	TEMPERATURE SWITCH FOR UC401D	8	ABN	185.00
HVAC	2HVR*TIS23E	LOCAL	TIS	TEMPERATURE SWITCH FOR UC401E	8	ABS	180.00
HVAC	2HVR*TIS23F	LOCAL	TIS	TEMPERATURE SWITCH FOR UC401F	8	ABS	180.00
HVAC	2HVR*UC401D	LOCAL	UC	UNIT COOLER	18	ABN	176.00
HVAC	2HVR*UC401E	LOCAL	UC	UNIT COOLER	18	ABS	177.00
HVAC	2HVR*UC401F	LOCAL	UC	UNIT COOLER	18	ABS	177.00

Table 3.1-1B Active Components

System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
HVAC	2HVR*UC402A	LOCAL	UC	UNIT COOLER	18	ABN	176.00
HVAC	2HVR*UC402B	LOCAL	UC	UNIT COOLER	18	ABN	177.00
HVAC	2HVR*UC408A	LOCAL	UC	ELEC MCC AREA UNIT CLR	18	ABN	250.00
HVAC	2HVR*UC408B	LOCAL	UC	ELEC MCC AREA UNIT CLR	18	ABN	250.00
HVAC	2HVR*UC409A	LOCAL	UC	ELEC MCC AREA UNIT CLR	18	ABS	250.00
HVAC	2HVR*UC409B	LOCAL	UC	ELEC MCC AREA UNIT CLR	18	ABS	250.00
HVAC	3-3-2HVRA90	2CEC*PNL870	GPI	RELAY FOR 2HVR*UC401A AND 2HVR*UC401D AND UC402A	25	CCR	306.00
HVAC	3-3-2HVRB90	2CEC*PNL871	GPI	RELAY FOR 2HVR*UC401B AND UC401C AND 401E AND 401F	25	CCR	306.00
HVAC	3-5-2HVRA90	2CEC*PNL870	GPI	RELAY FOR 2HVR*UC408A AND UC408B	25	CCR	306.00
HVAC	3-5-2HVRB90	2CEC*PNL871	GPI	RELAY FOR 2HVR*UC409A AND UC409B	25	CCR	306.00
HVAC	49-2HVRB18	2EJS*PNL104A	TOL	THERMAL OVERLOAD FOR 2HVR*UC408B	25	ABN	240.00
HVAC	49X-2HVPA10	2EJS*PNL102A	GPI	THEMAL OVERLOAD PROTECTION FOR 2HVP*UC1A		CCL	261.00
HVAC	49X-2HVPB10	2EJS*PNL301B	GPI	THEMAL OVERLOAD PROTECTION FOR 2HVP*UC1B		CCL	261.00
HVAC	49X-2HVPC10	2EHS*MCC201	GPI	THEMAL OVERLOAD PROTECTION FOR 2HVP*UC1C		CSH	261.00
HVAC	2EJS*PNL102A		PNL	600 VAC Distribution Panel	7	CB	261.00
ISC	2NMP*RE1617D	LOCAL	GM	NEUTRON FLUX DETECTOR LPRM TO APRM	8	PC	300.00
ISC	2NMP*RE2417D	LOCAL	GM	NEUTRON FLUX DETECTOR LPRM TO APRM	8	PC	300.00
ISC	2NMP*RE3217D	LOCAL	GM	NEUTRON FLUX DETECTOR LPRM TO APRM	8	PC	300.00
ISC	2CMS*LI9A	2CEC*PNL601	LI	SUPPRESSION POOL LEVEL INDICATOR		CB	306.00
ISC	2CMS*LI9B	2CEC*PNL898	LI	SUPPRESSION POOL LEVEL INDICATOR		CB	306.00
ISC	2CMS*LT9A	LOCAL	LT	LEVEL TRANSMITTER, MONITORS SUPPRESSION POOL LEVEL	8	SC	175.00
ISC	2CMS*LT9B	LOCAL	LT	LEVEL TRANSMITTER MONITORS SUPPRESSION POOL LEVEL	8	SC	179.00
ISC	2CMS*PI1A	2CEC*PNL601	PI	PRESSURE INDICATOR		CB	306.00
ISC	2CMS*PI1B	2CEC*PNL601	PI	PRESSURE INDICATOR		CB	306.00
ISC	2CMS*PI12A	2CEC*PNL601	PT	DRYWELL PRESSURE INDICATOR		CB	306.00

Table 3.1-1B Active Components

System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
ISC	2CMS*PT2B	2CEC*PNL898	PT	DRYWELL PRESSURE TRANSMITTER		CB	306.00
ISC	2CMS*PI17A	2CEC*PNL601	PT	DRYWELL PRESSURE INDICATOR		CB	306.00
ISC	2CMS*PT1A	LOCAL	PT	PRESSURE TRANSMITTER	8	SC	294.00
ISC	2CMS*PT1B	LOCAL	PT	PRESSURE TRANSMITTER	8	SC	289.00
ISC	2CMS*PT2A	LOCAL	PT	PRESSURE TRANSMITTER	8	SC	264.00
ISC	2CMS*PT2B	RAK105	PT	PRESSURE TRANSMITTER		SC	261.00
ISC	2CMS*PT7A	LOCAL	PT	PRESSURE TRANSMITTER	8	SC	255.00
ISC	2CMS*PT7B	RAK105	PT	PRESSURE TRANSMITTER		SC	261.00
HVAC	49-2HVRA18	2EJS*PNL104A	TOL	THERMAL OVERLOAD FOR 2HVR*UC408A		ABS	240.00
ISC	2CMS*PWRS9A	2CEC*PNL890	PWRS	ANALOG PROCESS UNIT		CRR	288.00
ISC	2CMS*PWRS9B	2CEC*PNL891	PWRS	ANALOG PROCESS UNIT		CRR	288.00
ISC	2CMS*TE101	LOCAL	TE	DRYWELL TEMPERATURE MONITOR	8	PC	307.00
ISC	2CMS*TE102	LOCAL	TE	DRYWELL TEMPERATURE MONITOR	8	PC	289.00
ISC	2CMS*TE103	LOCAL	TE	DRYWELL TEMPERATURE MONITOR	8	PC	283.00
ISC	2CMS*TE119	LOCAL	TE	DRYWELL TEMPERATURE MONITOR	8	PC	262.00
ISC	2CMS*TE120	LOCAL	TE	DRYWELL TEMPERATURE MONITOR	8	PC	262.00
ISC	2CMS*TE121	LOCAL	TE	DRYWELL TEMPERATURE MONITOR	8	PC	262.00
ISC	2CMS*TE67A	LOCAL	TE	SUPPRESSION POOL TEMPERATURE MONITOR	8	PC	223.00
ISC	2CMS*TE67B	LOCAL	TE	SUPPRESSION POOL TEMPERATURE MONITOR	8	PC	223.00
ISC	2CMS*TE68A	LOCAL	TE	SUPPRESSION POOL TEMPERATURE MONITOR	8	PC	223.00
ISC	2CMS*TE68B	LOCAL	TE	SUPPRESSION POOL TEMPERATURE MONITOR	8	PC	223.00
ISC	2CMS*TE69A	LOCAL	TE	SUPPRESSION POOL TEMPERATURE MONITOR	8	PC	223.00
ISC	2CMS*TE69B	LOCAL	TE	SUPPRESSION POOL TEMPERATURE MONITOR	8	PC	223.00
ISC	2CMS*TE70A	LOCAL	TE	SUPPRESSION POOL TEMPERATURE MONITOR	8	PC	223.00
ISC	2CMS*TE70B	LOCAL	TE	SUPPRESSION POOL TEMPERATURE MONITOR	8	PC	223.00
ISC	2CMS*TTX02	2CEC*PNL890	TE	DRYWELL TEMPERATURE MONITOR		CRR	288.00
ISC	2CMS*TTX103	2CEC*PNL890	TE	DRYWELL TEMPERATURE MONITOR		CRR	288.00
ISC	2CMS*TTY101	2CEC*PNL890	TE	DRYWELL TEMPERATURE MONITOR		CRR	288.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
ISC	2CMS*TTY02	2CEC*PNL890	TE	DRYWELL TEMPERATURE MONITOR		CRR	288.00
ISC	2CMS*TTY103	2CEC*PNL890	TE	DRYWELL TEMPERATURE MONITOR		CRR	288.00
ISC	2CMS*TTY119	2CEC*PNL891	TE	DRYWELL TEMPERATURE MONITOR		CRR	288.00
ISC	2CMS*TTY120	2CEC*PNL891	TE	DRYWELL TEMPERATURE MONITOR		CRR	288.00
ISC	2CMS*TTY121	2CEC*PNL891	TE	DRYWELL TEMPERATURE MONITOR		CRR	288.00
ISC	2CMS*TI174	2CEC*PNL601	TI	SUPPRESSION POOL TEMPERATURE INDICATOR		CB	306.00
ISC	2CMS*TI175	2CEC*PNL601	TI	SUPPRESSION POOL TEMPERATURE INDICATOR		CB	306.00
ISC	2CMS*TRX130	2CEC*PNL873	REC	DRYWELL TEMPERATURE RECORDER		CB	306.00
ISC	2CMS*TRY140	2CEC*PNL873	REC	DRYWELL TEMPERATURE RECORDER		CB	306.00
ISC	2CMS*TT67A	2CEC*PNL894	TT	SUPPRESSION POOL TEMPERATURE TRANSMITTER		CRR	288.00
ISC	2CMS*TT67B	2CEC*PNL895	TT	SUPPRESSION POOL TEMPERATURE TRANSMITTER		CRR	288.00
ISC	2CMS*TT68A	2CEC*PNL894	TT	SUPPRESSION POOL TEMPERATURE TRANSMITTER		CRR	288.00
ISC	2CMS*TT68B	2CEC*PNL895	TT	SUPPRESSION POOL TEMPERATURE TRANSMITTER		CRR	288.00
ISC	2CMS*TT69A	2CEC*PNL894	TT	SUPPRESSION POOL TEMPERATURE TRANSMITTER		CRR	288.00
ISC	2CMS*TT69B	2CEC*PNL895	TT	SUPPRESSION POOL TEMPERATURE TRANSMITTER		CRR	288.00
ISC	2CMS*TT70A	2CEC*PNL894	TT	SUPPRESSION POOL TEMPERATURE TRANSMITTER		CRR	288.00
ISC	2CMS*TT70B	2CEC*PNL895	TT	SUPPRESSION POOL TEMPERATURE TRANSMITTER		CRR	288.00
ISC	2ISC*LR1623A	2CEC*PNL601	LR	LEVEL RECORDER	8	CB	306.00
ISC	2ISC*LT105	2CES*RAK027	LT	LEVEL TRANSMITTER , MONITORS REACTOR VESSEL WATER LEVEL AND PROVIDES LEVEL SIGNALS TO 2ISC-LI1605		SC	261.00
ISC	2ISC*LT11A	2CES*RAK005	LT	LEVEL TRANSMITTER		SC	261.00
ISC	2ISC*LT11B	2CES*RAK027	LT	LEVEL TRANSMITTER		SC	261.00
ISC	2ISC*LT11C	2CES*RAK026	LT	LEVEL TRANSMITTER		SC	261.00
ISC	2ISC*LT11D	2CES*RAK004	LT	LEVEL TRANSMITTER		SC	261.00
ISC	2ISC*LT13A	2CES*RAK010	LT	FUEL ZONE LEVEL TRANSMITTER		SC	215.00
ISC	2ISC*LT13B	2CES*RAK009	LT	FUEL ZONE LEVEL TRANSMITTER		SC	215.00
ISC	2ISC*PT6A	2CES*RAK004	LT	RCS PRESSURE TRANSMITTER		SC	261.00

Table 3.1-1B Active Components

System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
ISC	2ISC*PT6B	2CES*RAK027	LT	RCS PRESSURE TRANSMITTER		SC	261.00
ISC	2ISC*LT7A	2CES*RAK005	LT	LEVEL TRANSMITTER , MONITOR THE REACTOR VESSEL WATER LEVEL AND PROVIDES LEVEL SIGNALS TO 2ISC*LIS1680C		SC	261.00
ISC	2ISC*LT7B	2CES*RAK027	LT	LEVEL TRANSMITTER , MONITORS THE REACTOR VESSEL WATER LEVEL AND PROVIDES LEVEL SIGNALS TO 2ISC*LIS1680B		SC	261.00
ISC	2ISC*LT7C	2CES*RAK005	LT	LEVEL TRANSMITTER , MONITORS THE REACTOR VESSEL WATER LEVEL AND PROVIDES LEVEL SIGNALS TO 2ISC*LIS1680A		SC	261.00
ISC	2ISC*LT7D	2CES*RAK005	LT	LEVEL TRANSMITTER , MONITORS THE REACTOR VESSEL WATER LEVEL AND PROVIDES SIGNALS TO 2ISC*LIS1680D		SC	261.00
ISC	2ISC*PDT110	2CES*RAK027	PDT	PRESSURE DIFFERENTIAL TRANSMITTER , MONITORS WIDE RANGE REACTORVESSEL WATER LEVEL		SC	261.00
ISC	2ISC*PDT14A	2CES*RAK005	PDT	PRESSURE DIFFERENTIAL TRANSMITTER , MONITORS WIDE RANGE REACTORVESSEL WATER LEVEL		SC	261.00
ISC	2ISC*PDT14B	2CES*RAK027	PDT	PRESSURE DIFFERENTIAL TRANSMITTER , MONITORS WIDE RANGE REACTORVESSEL WATER LEVEL		SC	261.00
ISC	2ISC*PDT14C	2CES*RAK005	PDT	PRESSURE DIFFERENTIAL TRANSMITTER , MONITORS WIDE RANGE REACTORVESSEL WATER LEVEL		SC	261.00
ISC	2ISC*PT15A	2CES*RAK005	PT	PRESSURE TRANSMITTER		SC	261.00
ISC	2ISC*PT15B	2CES*RAK027	PT	PRESSURE TRANSMITTER		SC	261.00
ISC	2ISC*PT15C	2CES*RAK005	PT	PRESSURE TRANSMITTER		SC	261.00
ISC	2ISC*PT15D	2CES*RAK004	PT	PRESSURE TRANSMITTER		SC	261.00
ISC	2VBS*PNLA103	N/A	PNL	120 VAC DIST PANEL	7	CB	306.00
ISC	2VBS*PNLB103	N/A	PNL	120 VAC DIST PANEL	7	CB	306.00
ISC	2NMP*RE4025C	LOCAL	GM	NEUTRON FLUX DETECTOR LPRM TO APRM	8	PC	
ISC	C51-PS31	2CEC*PNL608	PWR SUP	POWER SUPPLY		CB	306.00
ISC	C51-PS32	2CEC*PNL608	PWR SUP	POWER SUPPLY		CB	306.00

Table 3.1-1B Active Components

System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
ISC	C51-R603A	2CEC*PNL603	REC	NEUTRON FLUX RECORDER	8	CCR	306.00
ISC	C51-R603B	2CEC*PNL603	REC	NEUTRON FLUX RECORDER	8	CCR	306.00
ISC	2CEC*PNL601	N/A	PNL	ECCS Control Panel	5	CB	306.00
LPCS	2CSL*FIS107	2CEC*PNL629	FIS	FLOW IND SWITCH (LPCS 2CSL*P1 DISCHARGE FLOW)		CCR	306.00
LPCS	2CSL*FT107	LOCAL	FT	FLOW TRANSMITTER (LPCS 2CSL*P1 DISCHARGE FLOW)	0	SC	175.00
LPCS	2CSL*MOV104	LOCAL	MOV	LPCS INJECTION VALVE	14	SC	295.00
LPCS	2CSL*P1	LOCAL	P	LP CORE SPRAY PUMP	12	ABN	175.00
LPCS	2CSL*PDIS132	2CEC*PNL629	PDIS	(LPCS INJECTION VALVE 2CSL*MOV104 DIFF PRESSURE) DIFF PRESSURE IND SWITCH		CCR	306.00
LPCS	2CSL*PDT132	LOCAL	PDT	DIFF PRESSURE TRANSMITTER (LPCS 2CSL*MOV104 DIFFERENTIAL PRESSURE)		SC	175.00
LPCS	2CSL*STRT1	LOCAL	STRT	STRAINER-2CSL*P1	20	ABN	178.00
LPCS	E21A-K1	2CEC*PNL629	AGA	START SIGNAL FROM SEQUENCER - AUX RELAY	25	CB	306.00
LPCS	E21A-K10	2CEC*PNL629	AGA	LPCS INITIATION SIGNAL RELAY	25	CB	306.00
LPCS	E21A-K12	2CEC*PNL629	GE/HMA	AUX RELAY PUMP START	25	CB	306.00
LPCS	E21A-K14	2CEC*PNL629	AGA	AUX RELAY	25	CRR	306.00
LPCS	E21A-K50	2CEC*PNL629	AGA	INJECTION VALVE OPEN PERMISSIVE	25	CB	306.00
N2	2GSN*RV32A	LOCAL	RV	RELIEF VALVE - N2 SUPPLY TO ADS		SC	297.00
N2	2GSN*RV32B	LOCAL	RV	RELIEF VALVE - N2 SUPPLY TO ADS		SC	297.00
N2	2GSN*RV34A	LOCAL	RV	RELIEF VALVE - N2 SUPPLY TO ADS		NA	266.00
N2	2GSN*RV34B	LOCAL	RV	RELIEF VALVE - N2 SUPPLY TO ADS		NA	266.00
N2	2GSN-PCV144	LOCAL	PCV	N2 TO ADS ACC RCVR TKS PR	13	NA	261.00
N2	2GSN-PCV24A	LOCAL	PCV	ACT N2 VES TO H PRESS CON, PRESSURE CONTROL VALVE	13	NA	261.00
N2	2GSN-PCV24B	LOCAL	PCV	RES N2 VES TO H PRESS CON, PRESSURE CONTROL VALVE	13	NA	261.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
N2	2GSN-PSV20A	LOCAL	PSV	ACT N2 GAS SPLY VESSEL TK	13	NA	261.00
N2	2GSN-PSV20B	LOCAL	PSV	RES N2 GAS SPLY VESSEL TK	13	NA	261.00
N2	2GSN-PSV21A	LOCAL	PSV	ACT N2 GAS SPLY VESSEL TK	13	NA	261.00
N2	2GSN-PSV21B	LOCAL	PSV	RES N2 GAS SPLY VESSEL TK	13	NA	261.00
N2	2GSN-PSV30A	LOCAL	PSV	ACT N2 GAS SUPPLY VESSEL	13	NA	261.00
N2	2GSN-PSV30B	LOCAL	PSV	RES N2 GAS SUPPLY VESSEL	13	NA	261.00
N2	2GSN-RV147	LOCAL	RV	N2 TO ADS ACC RCVR TKS PRESS		NA	261.00
N2	2GSN-SV26A	LOCAL	SV	CONT CAB H PRESS ACT SPLY LINE	13	NA	261.00
N2	2GSN-SV26B	LOCAL	SV	CONT CAB H PRESS RES SPLY LINE	13	NA	261.00
N2	2GSN-TK3A	LOCAL	TK	N2 ACTIVE TANK	19	NA	261.00
N2	2GSN-TK3B	LOCAL	TK	N2 ACTIVE TANK	19	NA	261.00
N2	2GSN-TK3C	LOCAL	TK	N2 ACTIVE TANK	19	NA	261.00
N2	2GSN-TK3D	LOCAL	TK	N2 RESERVE TANK	19	NA	261.00
N2	2GSN-TK3E	LOCAL	TK	N2 RESERVE TANK	19	NA	261.00
N2	2GSN-TK3F	LOCAL	TK	N2 RESERVE TANK	19	NA	261.00
PCI	2DFR*MOV120	LOCAL	MOV	FLOOR AND EQUIPMENT DRAIN CONTAINMENT ISOLATION	14	SC	215.00
PCI	2DFR*MOV121	LOCAL	MOV	FLOOR AND EQUIPMENT DRAIN CONTAINMENT ISOLATION	14	PC	218.00
PCI	2MSS*AOV6A	LOCAL	AOV	MAIN STEAM ISOLATION VALVE	13	PC	251.00
PCI	2MSS*AOV7A	LOCAL	AOV	MAIN STEAM ISOLATION VALVE	13	MST	251.00
RCIC	2CEC*PNL642		PNL	RCIC LEAK DETECTION PANEL		CB	306.00
RCIC	2HVR*TIS30A	LOCAL	TIS	TEMPERATURE SWITCH FOR UC412A	8	SC	190.00
RCIC	2HVR*TIS30B	LOCAL	TIS	TEMPERATURE SWITCH FOR UC412B	8	SC	180.00
RCIC	2HVR*UC412A	LOCAL	UC	UNIT COOLER	18	SC	186.00
RCIC	2HVR*UC412B	LOCAL	UC	UNIT COOLER	18	SC	176.00
RCIC	2ICS*E1	LOCAL	E	TERRY TURBINE 2ICS*T1 LUBE OIL COOLER	20	SC	180.00
RCIC	2ICS*ED1	LOCAL	ED	DRAIN POT		SC	189.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
RCIC	2ICS*ED2	LOCAL	ED	DRAIN POT		SC	178.00
RCIC	2ISC*LS1693A	2CEC*PNL629	BISTABLE	RCS LEVEL 8 TRIP BISTABLE		CB	306.00
RCIC	2ISC*LS1693B	2CEC*PNL618	BISTABLE	RCS LEVEL 8 TRIP BISTABLE		CB	306.00
RCIC	2ISC*LS1693E	2CEC*PNL629	BISTABLE	RCS LEVEL 8 TRIP BISTABLE		CB	306.00
RCIC	2ISC*LS1693F	2CEC*PNL618	BISTABLE	RCS LEVEL 8 TRIP BISTABLE		CB	306.00
RCIC	2ICS*LT3A	LOCAL	LT	CONDENSATE STORAGE TANK LEVEL TRANSMITTER		PT	246.00
RCIC	2ICS*LT3C	LOCAL	LT	CONDENSATE STORAGE TANK LEVEL TRANSMITTER		PT	246.00
RCIC	2ICS*MOV116	LOCAL	MOV	RCIC LUBE OIL WATER SUPPL	14	SC	188.00
RCIC	2ICS*MOV120	LOCAL	MOV	RCIC STEAM SUPPLY VALVE TO TURB	14	SC	188.00
RCIC	2ICS*MOV120-33	LOCAL	ZS	2ICS*MOV120 LIMIT SWITCH (RCIC STEAM VALVE)	14	SC	188.00
RCIC	2ICS*MOV126	LOCAL	MOV	RCIC INJECTION SHUTOFF MOTOR OPERATED VALVE	14	SC	292.00
RCIC	2ICS*MOV129	LOCAL	MOV	MOTOR OPERATED VALVE FOR PUMP SUCT FROM CNDS STORAGE TANK	14	ABN	242.00
RCIC	2ICS*MOV136	LOCAL	MOV	RCIC PUMP SUCTION FROM SUPP POOL	14	SC	199.00
RCIC	2ICS*MOV150	LOCAL	MOV	2ICS*T1 TURB THROT MOTOR OPERATED VALVE; SUPPLIED W/EQP 2ICS*T1	14	SC	184.00
RCIC	2ICS*MOV159	LOCAL	MOV	MOTOR OPERATED BYPASS VALVE FOR 2ICS*MOV120	14	SC	188.00
RCIC	2ICS*P1	LOCAL	P	RCIC PUMP; TURBINE SHAFT DRIVE	11	SC	175.00
RCIC	2ICS*PCV115	LOCAL	PCV	LUBE OIL CLR PRESS CONT VALVE	13	SC	186.00
RCIC	2ICS*STRT3	LOCAL	STRT	TEMPORARY STRAINER	20	SC	183.00
RCIC	2ISC*LS1692A	2CEC*PNL629	LS	SLAVE TRIP UNIT, ACTUATES ON LOW RPV LEVEL TO ENABLE		CCR	306.00
RCIC	2ISC*LS1692B	2CEC*PNL629	LS	SLAVE TRIP UNIT, ACTUATES ON LOW RPV LEVEL TO ENABLE		CCR	306.00
RCIC	2ISC*LS1692E	2CEC*PNL629	LS	SLAVE TRIP UNIT, ACTUATES ON LOW RPV LEVEL TO ENABLE		CCR	306.00

Table 3.1-1B Active Components

System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
RCIC	2ISC*LS1692F	2CEC*PNL629	LS	SLAVE TRIP UNIT, ACTUATES ON LOW RPV LEVEL TO ENABLE		CCR	306.00
RCIC	3-6-2HVRA90	2CEC*PNL870	GPI	RELAY FOR 2HVR*UC412A	25	CCR	306.00
RCIC	3-6-2HVRB90	2CEC*PNL871	GPI	RELAY FOR 2HVR*UC412B	25	CCR	306.00
RCIC	E12-AT8	2CEC*PNL601	OPISOL	OPTICAL ISOLATOR		CCR	306.00
RCIC	E31A-K2A	2CEC*PNL632	AGA-GP1	RCIC ISOLATION RELAY	25	CB	306.00
RCIC	E31A-K2B	2CEC*PNL642	AGA-GP1	RCIC ISOLATION RELAY	25	CB	306.00
RCIC	E31A-K4A	2CEC*PNL632	AGA-GP1	LEAK DETECTION INPUT TO RCIC ISOLATION - AUX RELAY DE-ENERGIZE ON LEAK	25	CB	306.00
RCIC	E31A-K4B	2CEC*PNL642	AGA-GP1	LEAK DETECTION INPUT TO RCIC ISOLATION - AUX RELAY DE-ENERGIZE ON LEAK	25	CB	306.00
RCIC	E51A-K115	2CEC*PNL621	AGA-GP	HI WATER LEVEL TRIP - AUX RELAY	25	CB	306.00
RCIC	E51A-K116	2CEC*PNL621	AGA-GP	HI WATER LEVEL TRIP - AUX RELAY	25	CB	306.00
RCIC	E51A-K12	2CEC*PNL621	AGA-GP	LOW WATER LEVEL	25	CB	306.00
RCIC	E51A-K126	2CEC*PNL621	AGA-GP	OPEN PERMISSIVE FOR SUPPRESSION	25	CB	306.00
RCIC	E51A-K14	2CEC*PNL621	AGA-GP	HIGH VESSEL WATER LEVEL RELAY	25	CB	306.00
RCIC	E51A-K16	2CEC*PNL621	AGA-GP	LOW VESSEL WATER LEVEL	25	CB	306.00
RCIC	E51A-K2	2CEC*PNL621	AGA-GP	LOW VESSEL LEVEL INITIATION SIGNAL - AUX RELAY	25	CB	306.00
RCIC	E51A-K20	2CEC*PNL621	AGA-GP	AUX RELAY	25	CB	306.00
RCIC	E51A-K21	2CEC*PNL621	AGA-GP	CLOSE PERMISSIVE TO CONDENSATE STORAGE TANKS SUCTION VALVE	25	CB	306.00
RCIC	E51A-K3	2CEC*PNL621	AGA-GP	LOW LEVEL INITIATION SIGNAL - AUX RELAY	25	CB	306.00
RCIC	E51A-K60	2CEC*PNL621	AGA-GP	LOW LEVEL RPV CHANNEL SIGNAL - AUX RELAY	25	CB	306.00
RCIC	E51A-K62	2CEC*PNL621	AGA-GP	CHANNEL HIGH LEVEL SIGNAL - AUX RELAY	25	CB	306.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
RCIC	E51A-K80	2CEC*PNL621	AGA-TR	POOL SUCTION VALVE TIME DELAY OPEN PERMISSIVE FOR SUPPRESSION POOL SUCTION	25	CB	306.00
RCIC	E51A-K95	2CEC*PNL621	AGA-GP	HI WATER LEVEL TRIP - AUX RELAY	25	CB	306.00
RCIC	E51A-K96	2CEC*PNL621	AGA-GP	OPENS START UP VALVE - AUX RELAY	25	CB	306.00
RCIC	E51A-K97	2CEC*PNL621	AGA-GP	OPENS STEAM ADMISSION VALVE - TIME DELAY RELAY	25	CB	306.00
RCIC	2CEC*PNL632		PNL	RCIC LEAK DETECTION PANEL	5	CB	306.00
RHR	2RHS*E1A	LOCAL	HX	HEAT EXCHANGER	19	ABN	201.00
RHR	2RHS*E1B	LOCAL	HX	HEAT EXCHANGER	19	ABS	175.00
RHR	2RHS*FLS10A	LOCAL	FLS	SPECTACLE FLANGE FOR P1A DISCHARGE ISOLATION			ABN178.00
RHR	2RHS*FLS10B	LOCAL	FLS	SPECTACLE FLANGE FOR P1B DISCHARGE ISOLATION			ABS175.00
RHR	2RHS*FLS10C	LOCAL	FLS	SPECTACLE FLANGE FOR P1C DISCHARGE ISOLATION			ABS178.00
RHR	2RHS*FV38A	LOCAL	FV	RHR LOOP A TEST RETURN (SPC)	14	SC	206.00
RHR	2RHS*FV38B	LOCAL	FV	RHR LOOP A TEST RETURN (SPC)	14	SC	218.00
RHR	2RHS*MOV24C	LOCAL	MOV	LPCI C INJECTION , MOTOR OPERATED VALVE	14	SC	295.00
RHR	2RHS*MOV4A	LOCAL	MOV	RHR A MIN FLOW BYPASS , MOTOR OPERATED GATE VALVE	14	SC	202.00
RHR	2RHS*MOV4B	LOCAL	MOV	RHR B MIN FLOW BYPASS , MOTOR OPERATED VALVE	14	ABS	184.00
RHR	2RHS*MOV4C	LOCAL	MOV	RHR C MIN FLOW BYPASS , MOTOR OPERATED VALVE	14	ABS	184.00
RHR	2RHS*MOV8A	LOCAL	MOV	RHR H.E. E1A BYPASS MOTOR OPERATED VALVE	14	ABN	181.00
RHR	2RHS*MOV8B	LOCAL	MOV	RHR H.E. E1B BYPASS MOTOR OPERATED VALVE	14	ABS	184.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
RHR	2RHS*P1A	LOCAL	P	RHR PUMP	12	ABN	175.00
RHR	2RHS*P1B	LOCAL	P	RHR PUMP	12	ABS	175.00
RHR	2RHS*P1C	LOCAL	P	RHR PUMP	12	ABS	175.00
RHR	2RHS*PDIS24C	2CEC*PNL618	PDIS	ELECTRONIC MASTER TRIP UNIT		CCR	306.00
RHR	2RHS*PDT24C	2CES*RAK027	PDT	PRESSURE DIFFERENTIAL TRANSMITTER		SC	261.00
RHR	2RHS*STRT1A	LOCAL	STRT	T TYPE STRAINER FOR EQP 2RHS*P1A	20	ABN	178.00
RHR	2RHS*STRT1B	LOCAL	STRT	T TYPE STRAINER FOR EQP 2RHS*P1B	20	ABS	178.00
RHR	2RHS*STRT1C	LOCAL	STRT	T TYPE STRAINER FOR EQP 2RHS*P1C	20	ABS	178.00
RHR	2SWP*MOV33A	LOCAL	MOV	BUTTERFLY MOV	14	ABN	181.00
RHR	2SWP*MOV33B	LOCAL	MOV	BUTTERFLY MOV	14	ABS	181.00
RHR	2SWP*MOV90A	LOCAL	MOV	BUTTERFLY MOV	14	ABN	180.00
RHR	2SWP*MOV90B	LOCAL	MOV	BUTTERFLY MOV	14	ABS	181.00
RHR	E12A-K115A	2CEC*PNL629	AGA	INJECTION VALVE PERMISSIVE RELAY	25	CB	306.00
RHR	E12A-K115B	2CEC*PNL618	AGA	INJECTION VALVE PERMISSIVE RELAY	25	CB	306.00
RHR	E12A-K115C	2CEC*PNL618	AGA	INJECTION VALVE PERMISSIVE RELAY	25	CB	306.00
RHR	E12A-K18A	2CEC*PNL629	AGA	A PUMP START RELAY	25	CB	306.00
RHR	E12A-K18B	2CEC*PNL618	AGA	B PUMP START RELAY	25	CB	306.00
RHR	E12A-K21	2CEC*PNL618	GE/HMA	C PUMP START RELAY	25	CB	306.00
RHR	E12A-K30B	2CEC*PNL618	AGA	C PUMP RELAY	25	CB	306.00
RHR	E12A-K3A	2CEC*PNL629	AGA	LPCI B PUMP START	25	CB	306.00
RHR	E12A-K3B	2CEC*PNL618	AGA	LPCI B PUMP START	25	CB	306.00
SCRAM	2RDS*SOV126	LOCAL	SOV	SCRAM INLET (TYP OF 185)	13	SC	261.00
SCRAM	2RDS*SOV127	LOCAL	SOV	SCRAM OUTLET (TYP OF 185)	13	SC	261.00
SWS	2-2SWPA18	2CEC*PNL859	AGA (TDPU)	RELAY FOR 2SWP*MOV66A	25	CRR	288.00
SWS	2-2SWPB18	2CEC*PNL861	AGA (TDPU)	RELAY FOR 2SWP*MOV66B	25	CRR	288.00
SWS	2A-2SWPA01	2ENS*SWG101	AGA (TDPU)	RELAY FOR 2SWP*P1A	25	CSA	261.00
SWS	2A-2SWPB01	2ENS*SWG103	AGA (TDPU)	RELAY FOR 2SWP*P1B	25	CSB	261.00
SWS	2B-2SWPA01	2ENS*SWG101	AGA (TDPU)	RELAY FOR 2SWP*P1A	25	CSA	261.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
SWS	2B-2SWPB01	2ENS*SWG103	AGA (TDPU)	RELAY FOR 2SWP*P1B	25	CSB	261.00
SWS	2D-2SWPA01	2ENS*SWG101	AGA (TDPU)	RELAY FOR 2SWP*P1A	25	CSA	261.00
SWS	2D-2SWPB01	2ENS*SWG103	AGA (TDPU)	RELAY FOR 2SWP*P1B	25	CSB	261.00
SWS	2SWP*EJ2A	LOCAL	EJ	PUMP SUCTION EXPANSION JOINT	0	SW	224.00
SWS	2SWP*EJ2B	LOCAL	EJ	PUMP SUCTION EXPANSION JOINT	0	SW	224.00
SWS	2SWP*EJ2C	LOCAL	EJ	PUMP SUCTION EXPANSION JOINT	0	SW	224.00
SWS	2SWP*EJ2D	LOCAL	EJ	PUMP SUCTION EXPANSION JOINT	0	SW	224.00
SWS	2SWP*EJ2E	LOCAL	EJ	PUMP SUCTION EXPANSION JOINT	0	SW	224.00
SWS	2SWP*EJ2F	LOCAL	EJ	PUMP SUCTION EXPANSION JOINT	0	SW	224.00
SWS	2SWP*MOV19A	LOCAL	MOV	BUTTERFLY MOV	14	ABN	219.00
SWS	2SWP*MOV19B	LOCAL	MOV	BUTTERFLY MOV	14	ABN	219.00
SWS	2SWP*MOV3A	LOCAL	MOV	BUTTERFLY MOV	14	SW	265.00
SWS	2SWP*MOV3B	LOCAL	MOV	BUTTERFLY MOV	14	SW	265.00
SWS	2SWP*MOV50A	LOCAL	MOV	BUTTERFLY MOV	14	SW	265.00
SWS	2SWP*MOV50B	LOCAL	MOV	BUTTERFLY MOV	14	SW	264.00
SWS	2SWP*MOV599	LOCAL	MOV	BUTTERFLY MOV	14	PT	255.00
SWS	2SWP*MOV74A	LOCAL	MOV	BUTTERFLY MOV	14	SW	265.00
SWS	2SWP*MOV74B	LOCAL	MOV	BUTTERFLY MOV	14	SW	263.00
SWS	2SWP*MOV74C	LOCAL	MOV	BUTTERFLY MOV	14	SW	264.00
SWS	2SWP*MOV74D	LOCAL	MOV	BUTTERFLY MOV	14	SW	264.00
SWS	2SWP*MOV74E	LOCAL	MOV	BUTTERFLY MOV	14	SW	264.00
SWS	2SWP*MOV74F	LOCAL	MOV	BUTTERFLY MOV	14	SW	265.00
SWS	2SWP*MOV93A	LOCAL	MOV	BUTTERFLY MOV	14	SW	247.00
SWS	2SWP*MOV93B	LOCAL	MOV	BUTTERFLY MOV	14	PT	247.00
SWS	2SWP*P1A	LOCAL	P	SERVICE WATER PUMP, SERIAL N239B505-1	11	SW	224.00
SWS	2SWP*P1B	LOCAL	P	SERVICE WATER PUMP, SERIAL N239B505-2	11	SW	224.00
SWS	2SWP*P1C	LOCAL	P	SERVICE WATER PUMP, SERIAL N239B505-3	11	SW	224.00
SWS	2SWP*P1D	LOCAL	P	SERVICE WATER PUMP, SERIAL N239B505-4	11	SW	224.00

Table 3.1-1B Active Components							
System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
SWS	2SWP*P1E	LOCAL	P	SERVICE WATER PUMP, SERIAL N239B505-5	11	SW	224.00
SWS	2SWP*P1F	LOCAL	P	SERVICE WATER PUMP, SERIAL N239B505-6	11	SW	224.00
SWS	2SWP*PSLX66A	2CEC*PNL829	PS	PRESSURE SWITCH	0	CRR	288.00
SWS	2SWP*PSLX66B	2CEC*PNL830	PS	PRESSURE SWITCH	0	CRR	288.00
SWS	2SWP*STR4A	LOCAL	STR	STRAINER	20	SW	261.00
SWS	2SWP*STR4B	LOCAL	STR	STRAINER	20	SW	261.00
SWS	2SWP*STR4C	LOCAL	STR	STRAINER	20	SW	261.00
SWS	2SWP*STR4D	LOCAL	STR	STRAINER	20	SW	261.00
SWS	2SWP*STR4E	LOCAL	STR	STRAINER	20	SW	261.00
SWS	2SWP*STR4F	LOCAL	STR	STRAINER	20	SW	261.00
SWS	3-1-2SWPA44	2CEC*PNL859	GPD	RELAY FOR 2SWP*MOV3A AND 2SWP*MOV19A	25	CRR	288.00
SWS	3-1-2SWPB44	2CEC*PNL861	GPD	RELAY FOR 2SWP*MOV3B AND 2SWP*MOV19B	25	CRR	288.00
SWS	3-1-2SWPA18	2CEC*PNL859	GPI	RELAY FOR 2SWP*MOV66A	25	CRR	288.00
SWS	3-1-2SWPB18	2CEC*PNL861	GPI	RELAY FOR 2SWP*MOV66B	25	CRR	288.00
SWS	3-2-2SWPA44	2CEC*PNL859	GPD	RELAY FOR 2SWP*MOV599 AND 2SWP*MOV93A	25	CRR	288.00
SWS	3-2-2SWPB44	2CEC*PNL861	GPD	RELAY FOR 2SWP*MOV93B	25	CRR	288.00
SWS	3-2SWPA18	2CEC*PNL859	GPI	RELAY FOR 2SWP*MOV66A	25	CRR	288.00
SWS	3-2SWPB18	2CEC*PNL861	GPI	RELAY FOR 2SWP*MOV66B	25	CRR	288.00
SWS	3-3-2SWPA44	2CEC*PNL859	GPD	RELAY FOR 2SWP*MOV50A	25	CRR	288.00
SWS	3-3-2SWPB44	2CEC*PNL861	GPD	RELAY FOR 2SWP*MOV50B	25	CRR	288.00
SWS	3-6-2SWPA44	2CEC*PNL859	GPD	RELAY FOR 2SWP*MOV50A	25	CRR	288.00
SWS	3-6-2SWPB44	2CEC*PNL861	GPD	RELAY FOR 2SWP*MOV50B	25	CRR	288.00
SWS	52XB-2SWPB63	2CEC*PNL838	EGP	RELAY FOR 2SWP*MOV50B	25	CRR	288.00
SWS	52XD-2SWPB63	2CEC*PNL838	EGP	RELAY FOR 2SWP*MOV50B	25	CRR	288.00
SWS	52XF-2SWPB63	2CEC*PNL838	EGP	RELAY FOR 2SWP*MOV50B	25	CRR	288.00

Table 3.1-1B Active Components

System	Component-ID	Cabinet	Comp. Type	Description	Class	Bldg	EL
SWS	52X-2SWPA24	2EHS*MCC101	J10	RELAY FOR 2SWP*MOV74A	25	SW	261.00
SWS	52X-2SWPB24	2EHS*MCC301	J10	RELAY FOR 2SWP*MOV74B	25	SW	261.00
SWS	52X-2SWPC24	2EHS*MCC101	J10	RELAY FOR 2SWP*MOV74C	25	SW	261.00
SWS	52X-2SWPD24	2EHS*MCC301	J10	RELAY FOR 2SWP*MOV74D	25	SW	261.00
SWS	52X-2SWPE24	2EHS*MCC101	J10	RELAY FOR 2SWP*MOV74E	25	SW	261.00
SWS	52X-2SWPF24	2EHS*MCC301	J10	RELAY FOR 2SWP*MOV74F	25	SW	261.00
SWS	52XA-2SWPA63	2CEC*PNL837	EGP	RELAY FOR 2SWP*MOV50A	25	CRR	288.00
SWS	52XC-2SWPA63	2CEC*PNL837	EGP	RELAY FOR 2SWP*MOV50A	25	CRR	288.00
SWS	52XE-2SWPA63	2CEC*PNL837	EGP	RELAY FOR 2SWP*MOV50A	25	CRR	288.00
SWS	62-2SWPA24	2EHS*MCC101	AGA (TDPU)	RELAY FOR 2SWP*MOV74A	25	SW	261.00
SWS	62-2SWPB24	2EHS*MCC301	AGA (TDPU)	RELAY FOR 2SWP*MOV74B	25	SW	261.00
SWS	62-2SWPC24	2EHS*MCC101	AGA (TDPU)	RELAY FOR 2SWP*MOV74C	25	SW	261.00
SWS	62-2SWPD24	2EHS*MCC301	AGA (TDPU)	RELAY FOR 2SWP*MOV74D	25	SW	261.00
SWS	62-2SWPE24	2EHS*MCC101	AGA (TDPU)	RELAY FOR 2SWP*MOV74E	25	SW	261.00
SWS	62-2SWPF24	2EHS*MCC301	AGA (TDPU)	RELAY FOR 2SWP*MOV74F	25	SW	261.00
SWS	99-11-2SWPB65	2CEC*PNL837	OPTISOL	OPTICAL ISOLATOR		CRR	288.00
SWS	99-11X-2SWPA65	2CEC*PNL837	EGPD	RELAY FOR 2SWP*MOV50A	25	CRR	288.00
SWS	99-11X-2SWPB65	2CEC*PNL838	EGPD	RELAY FOR 2SWP*MOV50B	25	CRR	288.00
SWS	99-12X-2SWPA44	2CEC*PNL838	MDR	RELAY FOR 2SWP*MOV50B	25	CRR	288.00
SWS	99-12X-2SWPB44	2CEC*PNL838	MDR	RELAY FOR 2SWP*MOV50A	25	CRR	288.00
SWS	99-11-2SWPA65	2CEC*PNL838		OPTICAL ISOLATOR		CRR	288.00
SWS	2CEC*PNL830		PANEL	BOP INSTRUMENT PANEL DIV II	5	CB	288.00
SWS	2CEC*PNL837		PANEL	BOP INSTRUMENT PANEL DIV I	5	CB	288.00

Table 3.1-2 Review of IPE Systems and Event Tree Top Events				
No.	System	Description	Top Events in Seismic Success Path	Top Events Not in Seismic Success Path
1	HPCS	High Pressure Core Spray	HS: HPCS	
2	RCIC	Reactor Core Isolation Cooling	IC: RCIC	U1, U2, U3: RCIC Station Blockout (SBO) IL: Operator overrides ATWS Trips OA: Operator sheds DC loads (SBO)
3	LPCS	Low Pressure Core Spray	LS: LPCS	
4	RHR	Residual Heat Removal	LA, LB: RHR A/B pump train (SPC) HA, HB: RHR A/B heat exchanger (SPC) LC: LPCI injection train PA, PB: A/B suppression pool cooling OH: Operator aligns RHR cooling	IA, IB: LPCI injection train CA, CB: A/B containment spray
5	ECCS	ECCS Actuation System	E1, E2: Div. I/II ECCS actuation	ME: Manual ECCS actuation
6	AC	AC Power System	A1, A2: Div. I/II Emergency AC UA, UB: Vital UPS source A/B	Top events OG (Offsite power), KA, KB (115Kv source A/B), NA, NB (Normal AC & DC switchgear), KR (Partial recovery of KA/KB) are all dependent on normal offsite power.
7	DC	DC Power System	D1, D2: Div. I/II Emergency DC	
8	SWS	Service water	SA, SB: Div I/II Service Water	
9	F&SWC	Fire & Service Water Crossties		SW: Service Water - RHR crosstie FP: Fire Water - RHR crosstie S1 - S3: Fire Water - RHR crosstie (SBO)
10	PCI	Containment Isolation		IS: Containment isolation (level 2)
11	HVAC	Ventilation System	MA, MB: South/North Aux. Bldg MCC & pump area unit coolers. Room Cooling is also included in HPCS & RCIC.	

Table 3.1-2 Review of IPE Systems and Event Tree Top Events

No.	System	Description	Top Events in Seismic Success Path	Top Events Not in Seismic Success Path
12	SLC	Standby Liquid Control		SL: Standby Liquid Control System (ATWS)
13	ADS	Automatic Depressurization System	SV: SRV/ADS valves	OD: Operator depressurizes O1, O2, O3: Operator depress. (SBO) X1, X2, X3: SRVs remain open (SBO) AI: ADS inhibit (ATWS) OE: Op. Emerg. Depress. (ATWS) SR: Adequate relief (ATWS) SO: Stuck open relief valve (ATWS)
14	CDS	Control Rod Drive		CF: Injection at containment failure (Level 2)
15	RPS	Reactor Protection System	QM: Reactor scram mechanical equip. QE: Reactor scram electrical equip.	RQ: Reactor scram MS: Mode switch in shutdown
16	RRCS	Redundant Reactivity Control System		C1, C2: Div I/II RRCS (ATWS) CH: Level control not high (ATWS) WL: RPV Level > 1/2 core (ATWS) MO: Operator overrides Level 1 (ATWS) RI: Alternate Rod Insertion (ATWS) RT: Recirc. Pump Trip (ATWS) FT: Feedwater Runback (ATWS)
17	CV	Containment Venting	CV: Containment venting	GV: Gas Venting (level 2) VC: Containment venting (level 2) FB: Drywell venting (level 2) FD: Drywell venting (level 2)
18	VS	Vapor Suppression	VS: Vapor suppression	OV: Operator sprays or vents
19	RBCLC	Reactor Building Closed Loop Cooling Water		RW: RBCLC depends on normal AC

Table 3.1-2 Review of IPE Systems and Event Tree Top Events				
No.	System	Description	Top Events in Seismic Success Path	Top Events Not in Seismic Success Path
20	TBCLC	Turbine Building Closed Loop Cooling Water		TW: TBCLC depends on normal AC
21	CN&FW	Condensate & Feedwater systems		TA, TB: A/B Condensate Storage Tank FW: Feedwater depends on normal AC CN: Condenser depends on normal AC
22	N2	Nitrogen System	N1: High pressure nitrogen The common head of N1 & N2	N2: Nitrogen depends on normal AC
23	INSTR	Instrument Air		AS: Instrument air depends on normal AC
24	LCF	Late Containment Failure		CI & CF: Containment failure (level 2)
25	RR	Reactor Recirculation - Seal LOCA		Seal LOCA not modeled
26	RCR	Recovery		R1: Normal AC power recovery I1-I5: Offsite AC recovery (SBO) G1-G5: Emergency EDG recovery (SBO)
27	RPVV	RPV Venting		Level 2
28	ISC	Vessel and Containment Instrumentation	Included in several IPE models	

Table 3.1-3 Relay Chatter Functional Evaluation Results					
Relay	System	Location	Type	Contactor	GERS
E51A-K15	RCIC	2CEC*PNL621	AGA-GP	D/O	B-29
E51A-K24	RCIC	2CEC*PNL621	AGA-GP	D/O	B-29
E51A-K120	RCIC	2CEC*PNL621	AGA-TR	D/O	B-29
E51A-K121	RCIC	2CEC*PNL618	AGA-TR	D/O	B-29
E51A-K84	RCIC	2CEC*PNL618	AGA-TR	D/O	B-29
E51A-K85	RCIC	2CEC*PNL618	AGA-TR	D/O	B-29
E51A-K64	RCIC	2CEC*PNL621	AGA-TR	D/O	B-29
E51A-K65	RCIC	2CEC*PNL621	AGA-TR	D/O	B-29
E51A-K8	RCIC	2CEC*PNL621	AGA-GP	D/O	B-29
E51A-K67	RCIC	2CEC*PNL621	AGA-GP	D/O	B-29
E51A-K72	RCIC	2CEC*PNL621	AGA-GP	D/O	B-29
E51A-K33	RCIC	2CEC*PNL618	AGA-GP	D/O	B-29
E51A-K87	RCIC	2CEC*PNL618	AGA-GP	D/O	B-29
E51A-K88	RCIC	2CEC*PNL618	AGA-GP	D/O	B-29
E51A-K68	RCIC	2CEC*PNL621	AGA-GP	D/O	B-29
E51A-K69	RCIC	2CEC*PNL621	AGA-GP	D/O	B-29
E51A-K86	RCIC	2CEC*PNL618	AGA-GP	D/O	B-29
E51A-K79	RCIC	2CEC*PNL618	AGA-GP	D/O	B-29
E51A-K66	RCIC	2CEC*PNL621	AGA-GP	D/O	B-29
E51A-K78	RCIC	2CEC*PNL621	AGA-GP	D/O	B-29
E51A-K97	RCIC	2CEC*PNL621	AGA-TR	D/O & E/C	B-29
K9-945E400[1]	HPCS	2CES*IPNL413	GE-184C5506G002	E/O	
K10-945E400[1]	HPCS	2CES*IPNL413	GE-184C5506G002	E/O	
K11-945E400[1]	HPCS	2CES*IPNL413	GE-184C5506G002	E/O	
K12-945E400[1]	HPCS	2CES*IPNL413	GE-184C5506G002	E/O	
K15-945E400[1]	HPCS	2CES*IPNL413	GE-SJ DA 213A6947P005	D/O	
K28-945E400[1]	HPCS	2CES*IPNL413	GE-184C5506G002	D/O	
E22B-K39	HPCS	2ENS*SWG102	HFA	D/O	B-18
E22B-K6	HPCS	2ENS*SWG102	HMA	D/O	B-19
E22B-K36	HPCS	2ENS*SWG102	HEA61B	D/O	B-61
E22B-K1	HPCS	2ENS*SWG102	HEA61C	D/O	B-61
E22B-K14	HPCS	2ENS*SWG102	GE-184C5506G002	D/O	
E22B-K15	HPCS	2ENS*SWG102	HMA	D/O	B-19
E22B-K11	HPCS	2ENS*SWG102	HFA	E/C	B-18
E22B-K30A	HPCS	2ENS*SWG102	PVD21BA	D/O	B-92
E22B-K30B	HPCS	2ENS*SWG102	PVD21BA	D/O	B-92
E22B-K30C	HPCS	2ENS*SWG102	PVD21BA	D/O	B-92
E22B-K32	HPCS	2ENS*SWG102	ICW51A	D/O	

Table 3.1-3 Relay Chatter Functional Evaluation Results

Relay	System	Location	Type	Contactor	GERS
E22B-K35A	HPCS	2ENS*SWG102	IJCV510	D/O	
E22B-K35B	HPCS	2ENS*SWG102	IJCV510	D/O	
E22B-K35C	HPCS	2ENS*SWG102	IJCV510	D/O	
E22B-K37	HPCS	2ENS*SWG102	IAV51K	D/O	
E22B-K31	HPCS	2ENS*SWG102	CEH51A	D/O	
27NX-2ENSC13	HPCS	2ENS*SWG102	HMA111B2	D/O & E/C	B-19
27NY-2ENSC14	HPCS	2ENS*SWG102	HMA111B2	D/O & E/C	B-19
27SX-2ENSC13	HPCS	2ENS*SWG102	HMA111B2	D/O & E/C	B-19
27SY-2ENSC14	HPCS	2ENS*SWG102	HMA111B2	D/O & E/C	B-19
27N1-2ENSC05	HPCS	2ENS*SWG102	NGV13B	E/C & D/O	B-92
27S1-2ENSC06	HPCS	2ENS*SWG102	NGV13B	E/C & D/O	B-92
27S2-2ENSC06	HPCS	2ENS*SWG102	NGV13B	E/C & D/O	B-92
27N2-2ENSC05	HPCS	2ENS*SWG102	NGV13B	E/C & D/O	B-92
50/51-1-2EJSX07	HPCS	2ENS*SWG102	IFC51B	D/O	
50/51-2-2EJSX07	HPCS	2ENS*SWG102	IFC51B	D/O	
50/51-3-2EJSX07	HPCS	2ENS*SWG102	IFC51B	D/O	
86T-2EJSX07	HPCS	2ENS*SWG102	HEA	D/O	B-61
86P-2CSHN01	HPCS	2ENS*SWG102	HEA	D/O	B-61
62-1-2CSHN01	HPCS	2ENS*SWG102	SAM11B	D/O	B-92
81-2CSHN01	HPCS	2ENS*SWG102	ITE-81	D/O	
81X-2CSHN01	HPCS	2ENS*SWG102	HAA15A5F	D/O	
50B-2CSHN01	HPCS	2ENS*SWG102	HFC23	D/O	
50/51-1-2CSHN01	HPCS	2ENS*SWG102	IFC66KD1A	D/O	
50/51-2-2CSHN01	HPCS	2ENS*SWG102	IFC66KD1A	D/O	
50/51-3-2CSHN01	HPCS	2ENS*SWG102	IFC66KD1A	D/O	
E22B-K1	HPCS	2CES*IPNL413	HEA61C	D/O	B-61
E22B-K36	HPCS	2CES*IPNL413	HEA61B	D/O	B-61
27X1-2ENSC10	HPCS	2ENS*SWG102	HFA	D/O	B-18
E12A-K25	LPCI-C	2CEC*PNL618	AGA-GP	D/O & E/C	B-29
E12A-K115C	LPCI-C	2CEC*PNL618	AGA-GP	D/O & E/C	B-29
E12A-K9B	LPCI-C	2CEC*PNL618	AGA-GP	D/O & E/C	B-29
E12A-K30B	LPCI-C	2CEC*PNL618	AGA-GP	D/O & E/C	B-29
E12A-K21	LPCI-C	2CEC*PNL618	HMA	D/O & E/C	B-19
86-2RHSC01	LPCI-C	2ENS*SWG103	HEA	D/O	
50G-2RHSC52	LPCI-C	2ENS*SWG103	HFA	D/O	
50-2RHSC51	LPCI-C	2ENS*SWG103	IFC	D/O	
51-2RHSC51	LPCI-C	2ENS*SWG103	IFC	D/O	
27X2-2ENSYO4	LPCI-C	2ENS*SWG103	HFA	D/O & E/C	B-18

Table 3.1-3 Relay Chatter Functional Evaluation Results					
Relay	System	Location	Type	Contactor	GERS
86-2CSLN01	LPCS	2ENS*SWG101	HEA	D/O	
50G-2CSLN52	LPCS	2ENS*SWG101	HFA	D/O	
50-2CSLN51	LPCS	2ENS*SWG101	IFC	D/O	
51-2CSLN51	LPCS	2ENS*SWG101	IFC	D/O	
27X2-2ENSXO4	LPCS	2ENS*SWG101	HFA	D/O & E/C	B-18
86-2RHSA01	RHR-A	2ENS*SWG101	HEA	D/O	
50G-2RHSA52	RHR-A	2ENS*SWG101	HFA	D/O	
50-2RHSA51	RHR-A	2ENS*SWG101	IFC	D/O	
51-2RHSA51	RHR-A	2ENS*SWG101	IFC	D/O	
27X1-2ENSXO4	RHR-A	2ENS*SWG101	HFA	D/O & E/C	B-18
86-2RHSB01	RHR-B	2ENS*SWG103	HEA	D/O	
50G-2RHSB52	RHR-B	2ENS*SWG103	HFA	D/O	
50-2RHSB51	RHR-B	2ENS*SWG103	IFC	D/O	
51-2RHSB51	RHR-B	2ENS*SWG103	IFC	D/O	
27X1-2ENSYO4	RHR-B	2ENS*SWG103	HFA	D/O & E/C	B-18
50/51-2EJSA02	AC	2ENS*SWG101	IFC	D/O	
50G-2EJSA03	AC	2ENS*SWG101	HFC	D/O	
86-2EJSX02	AC	2ENS*SWG101	HEA	D/O	
50/51-2EJSB02	AC	2ENS*SWG103	IFC	D/O	
50G-2EJSB03	AC	2ENS*SWG103	HFC	D/O	
86-2EJSY03	AC	2ENS*SWG103	HEA	D/O	
86-2EGPX01	AC	2ENS*SWG101	HEA	D/O	B-61
86GX1-2EGSA01	AC	2CES*IPNL406	AGA-GPDR	D/O	
48CL1-2EGSA01	AC	2CES*IPNL406	AGA-GPDR	E/C	
48CL2-2EGSA06	AC	2CES*IPNL406	AGA-GPDR	E/C	
87G-2EGPX01	AC	2ENS*SWG101	PVD	D/O	
86-2EGPY01	AC	2ENS*SWG103	HEA	D/O	B-61
86GX1-2EGSB01	AC	2CES*IPNL408	AGA-GPDR	D/O	
48CL1-2EGSB01	AC	2CES*IPNL408	AGA-GPDR	E/C	
48CL2-2EGSB06	AC	2CES*IPNL408	AGA-GPDR	E/C	
87G-2EGPY01	AC	2ENS*SWG103	PVD	D/O	
27X3-2ENSX04	AC	2ENS*SWG101	HFA	D/O & E/C	B-18
27X4-2ENSX04	AC	2ENS*SWG101	HFA	D/O & E/C	B-18
27X5-2ENSX04	AC	2ENS*SWG101	HFA	D/O & E/C	B-18
94-2ENSX04	AC	2ENS*SWG101	HFA	D/O & E/C	B-18
27AX-2ENSX05	AC	2ENS*SWG101	HFA	D/O & E/C	B-18
27AY-2ENSX05	AC	2ENS*SWG101	HFA	D/O & E/C	B-18
27AZ-2ENSX05	AC	2ENS*SWG101	HFA	D/O & E/C	B-18

Table 3.1-3 Relay Chatter Functional Evaluation Results

Relay	System	Location	Type	Contactor	GERS
27BX-2ENSX06	AC	2ENS*SWG101	HFA	D/O & E/C	B-18
27BY-2ENSX06	AC	2ENS*SWG101	HFA	D/O & E/C	B-18
27BZ-2ENSX06	AC	2ENS*SWG101	HFA	D/O & E/C	B-18
62-2-2ENSX06	AC	2ENS*SWG101	TD-5 TR	D/O & E/C	
62-3-2ENSX06	AC	2ENS*SWG101	TD-5 TR	D/O & E/C	
62-1-2ENSX05	AC	2ENS*SWG101	SAM TU	D/O & E/C	
27X3-2ENSY04	AC	2ENS*SWG103	HFA	D/O & E/C	B-18
27X4-2ENSY04	AC	2ENS*SWG103	HFA	D/O & E/C	B-18
27X5-2ENSY04	AC	2ENS*SWG103	HFA	D/O & E/C	B-18
94-2ENSY04	AC	2ENS*SWG103	HFA	D/O & E/C	B-18
27AX-2ENSY05	AC	2ENS*SWG103	HFA	D/O & E/C	B-18
27AY-2ENSY05	AC	2ENS*SWG103	HFA	D/O & E/C	B-18
27AZ-2ENSY05	AC	2ENS*SWG103	HFA	D/O & E/C	B-18
27BX-2ENSY06	AC	2ENS*SWG103	HFA	D/O & E/C	B-18
27BY-2ENSY06	AC	2ENS*SWG103	HFA	D/O & E/C	B-18
27BZ-2ENSY06	AC	2ENS*SWG103	HFA	D/O & E/C	B-18
62-2-2ENSY06	AC	2ENS*SWG103	TD-5 TR	D/O & E/C	
62-3-2ENSY06	AC	2ENS*SWG103	TD-5 TR	D/O & E/C	
62-1-2ENSY05	AC	2ENS*SWG103	SAM TU	D/O & E/C	
B22C-K8A	ADS	2CEC*PNL628	AGA-GP	D/O	B-29
B22C-K8E	ADS	2CEC*PNL628	AGA-GP	D/O	B-29
B22C-K8B	ADS	2CEC*PNL631	AGA-GP	D/O	B-29
B22C-K8F	ADS	2CEC*PNL631	AGA-GP	D/O	B-29
27X1-2ENSX04	SW	2ENS*SWG101	HFA	D/O	
62-1-2SWPA01	SW	2ENS*SWG101	AGA - TDPU	D/O	
86-2SWPA01	SW	2ENS*SWG101	HEA	D/O	
50G-2SWPA52	SW	2ENS*SWG101	HFC	D/O	
50-2SWPA51	SW	2ENS*SWG101	HFC	D/O	
51-2SWPA51	SW	2ENS*SWG101	ITE 51L	D/O	
27X1-2ENSY04	SW	2ENS*SWG103	HFA	D/O	
62-1-2SWPB01	SW	2ENS*SWG103	AGA - TDPU	D/O	
86-2SWPB01	SW	2ENS*SWG103	HEA	D/O	
50G-2SWPB52	SW	2ENS*SWG103	HFC	D/O	
50-2SWPB51	SW	2ENS*SWG103	HFC	D/O	
51-2SWPB51	SW	2ENS*SWG103	ITE 51L	D/O	
27X2-2ENSX04	SW	2ENS*SWG101	HFA	D/O	
62-1-2SWPC01	SW	2ENS*SWG101	AGA - TDPU	D/O	
3-2SWPC01	SW	2ENS*SWG101	HFA	D/O	

Table 3.1-3 Relay Chatter Functional Evaluation Results					
Relay	System	Location	Type	Contactor	GERS
3-7-2SWPA44	SW	2ENS*SWG101	GPD	D/O	
86-2SWPC01	SW	2ENS*SWG101	HEA	D/O	
50G-2SWPC52	SW	2ENS*SWG101	HFC	D/O	
50-2SWPC51	SW	2ENS*SWG101	HFC	D/O	
51-2SWPC51	SW	2ENS*SWG101	ITE 51L	D/O	
27X2-2ENSY04	SW	2ENS*SWG103	HFA	D/O	
62-1-2SWPD01	SW	2ENS*SWG103	AGA - TDPU	D/O	
3-2SWPD01	SW	2ENS*SWG103	HFA	D/O	
3-7-2SWPB44	SW	2ENS*SWG103	GPD	D/O	
86-2SWPD01	SW	2ENS*SWG103	HEA	D/O	
50G-2SWPD52	SW	2ENS*SWG103	HFC	D/O	
50-2SWPD51	SW	2ENS*SWG103	HFC	D/O	
51-2SWPD51	SW	2ENS*SWG103	ITE 51L	D/O	
27X3-2ENSX04	SW	2ENS*SWG101	HFA	D/O	
62-1-2SWPE01	SW	2ENS*SWG101	AGA - TDPU	D/O	
3-2SWPE01	SW	2ENS*SWG101	HFA	D/O	
3-7-2SWPA44	SW	2ENS*SWG101	GPD	D/O	
86-2SWPE01	SW	2ENS*SWG101	HEA	D/O	
50G-2SWPE52	SW	2ENS*SWG101	HFC	D/O	
50-2SWPE51	SW	2ENS*SWG101	HFC	D/O	
51-2SWPE51	SW	2ENS*SWG101	ITE 51L	D/O	
27X3-2ENSY04	SW	2ENS*SWG103	HFA	D/O	
62-1-2SWPF01	SW	2ENS*SWG103	AGA - TDPU	D/O	
3-2SWPF01	SW	2ENS*SWG103	HFA	D/O	
3-7-2SWPB44	SW	2ENS*SWG103	GPD	D/O	
86-2SWPF01	SW	2ENS*SWG103	HEA	D/O	
50G-2SWPF52	SW	2ENS*SWG103	HFC	D/O	
50-2SWPF51	SW	2ENS*SWG103	HFC	D/O	
51-2SWPF51	SW	2ENS*SWG103	ITE 51L	D/O	

Notes:

1. Relays (6 of the HPCS relays) do not have a component Id (K9, K10, K11, K12, K15 and K28) and are followed by the drawing series where the relays are identified. This is how GE separates the relays in the DG control panel from other HPCS logic relays located in the main control room panels.

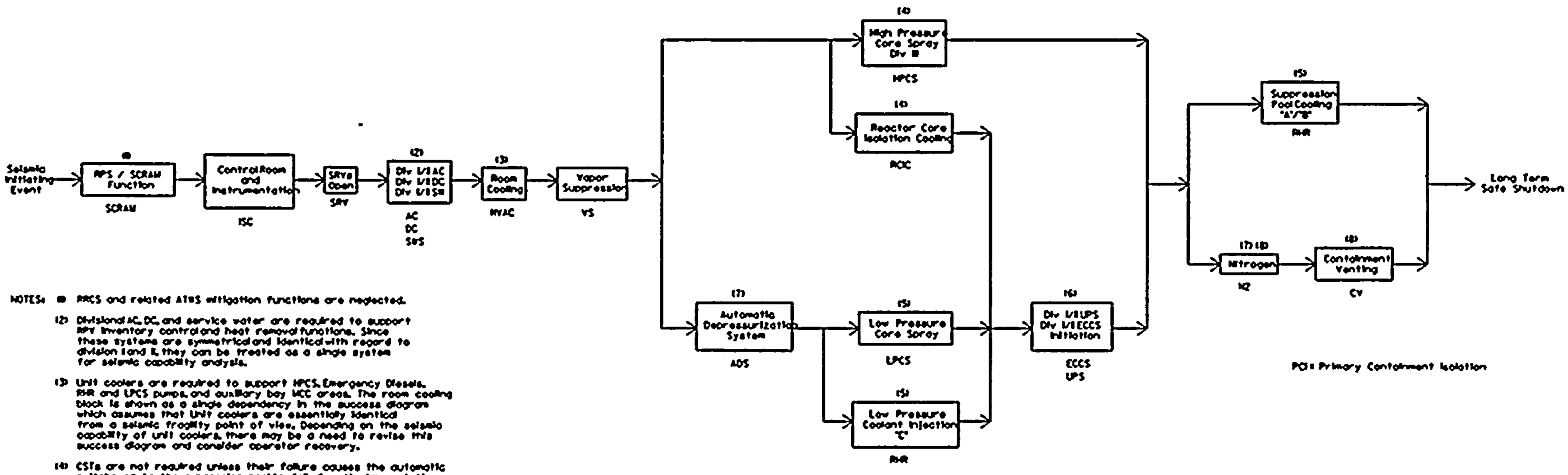
Table 3.1-4 RCIC Relay Chatter			
Relay	Model	Location	Effects
E51A-K15	AGA-GP	P621	trip turbine - seal in
E51A-K24	AGA-GP	P621	trip turbine - no seal in
E51A-K120	AGA-TR	P621	1 sec time delay - trip turbine
E51A-K2	AGA-GP	P621	starts RCIC
E51A-K67	AGA-GP	P621	trip & throttle valve closure, Note 1
E51A-K72	AGA-GP	P621	trip & throttle valve closure, Note 1
E51A-K5	AGA-GP	P621	
E51A-K33	AGA-GP	P618	trip turbine - seal in
E51A-K54	AGA-GP	P618	no impact
E51A-K121	AGA-TR	P618	1 sec time delay - trip turbine
E51A-K64	AGA-TR	P621	3 sec time delay - trip turbine, Note 2
E51A-K65	AGA-TR	P621	3 sec time delay - trip turbine, Note 2
E51A-K84	AGA-TR	P618	3 sec time delay - trip turbine, Note 2
E51A-K85	AGA-TR	P618	3 sec time delay - trip turbine, Note 2
E51A-K8	AGA-GP	P621	trips turbine, Note 1
E51A-K87	AGA-GP	P618	both 87 & 88 must chatter, Note 2
E51A-K88	AGA-GP	P618	both 87 & 88 must chatter, Note 2
E51A-K68	AGA-GP	P621	both 68 & 69 must chatter, Note 2
E51A-K69	AGA-GP	P621	both 68 & 69 must chatter, Note 2
E51A-K86	AGA-GP	P618	both 86 &79 must chatter, Note 2
E51A-K79	AGA-GP	P618	both 86 &79 must chatter, Note 2
E51A-K66	AGA-GP	P621	both 66 &78 must chatter, Note 2
E51A-K78	AGA-GP	P621	both 66 &78 must chatter, Note 2

Table 3.1-4 RCIC Relay Chatter			
Relay	Model	Location	Effects
E51A-K20	AGA-GP	P621	momentarily start to close injection valve, no seal in & valve opens after
E51A-K19	AGA-GP	P621	momentarily start to close injection valve, no seal in & valve opens after
E51A-K40	AGA-GP	P621	momentarily start to close injection valve, no seal in & valve opens after
E51A-K97	AGA-TR	P621	opens main steam admission valve, turbine trips on overspeed
E51A-K23	AGA-GP	H13-P629	opens cond drain trap bypass
E51A-K128	AGA-TDPU	P621	opens cond pot drain
E51A-K129	AGA-TDDO	P621	opens cond pot drain

Notes:

(1) Chatter of E51A-K67, 72 or 8 will result in closure of the trip & throttle valve. If a LOCA signal is present the valve can not be reopened. The LOCA signal, E12A-K110A is actuated by E 21A-K11 which will be sealed in if there is a LOCA signal or if E21A-K10 seals in. RCIC injection valve is also closed.

(2) Chatter of E51A-K15, 24, 64, 120, 65, 66 & 78, 68 & 69, 33, 121, 84, 85, 87 & 88, 79 & 86, will result in addition to the above (K67, K72 or K8 chatter) isolation of steam supply isolation valves 2ICS*MOV121 & 128.



NOTES:

(1) RRCS and related ATWS mitigation functions are neglected.

(2) Divisional AC, DC, and service water are required to support RPV inventory control and heat removal functions. Since these systems are symmetrical and identical with regard to division I and II, they can be treated as a single system for seismic capability analysis.

(3) Unit coolers are required to support HPCS, Emergency Diesels, RHR and LPCS pumps, and auxiliary bay MCC areas. The room cooling block is shown as a single dependency in the success diagram which assumes that Unit coolers are essentially identical from a seismic fragility point of view. Depending on the seismic capability of unit coolers, there may be a need to revise this success diagram and consider operator recovery.

(4) CSTs are not required unless their failure causes the automatic switchover to the supression pool to fail. (Level instrumentation must successfully provide transfer function for HPCS and RCIC success)

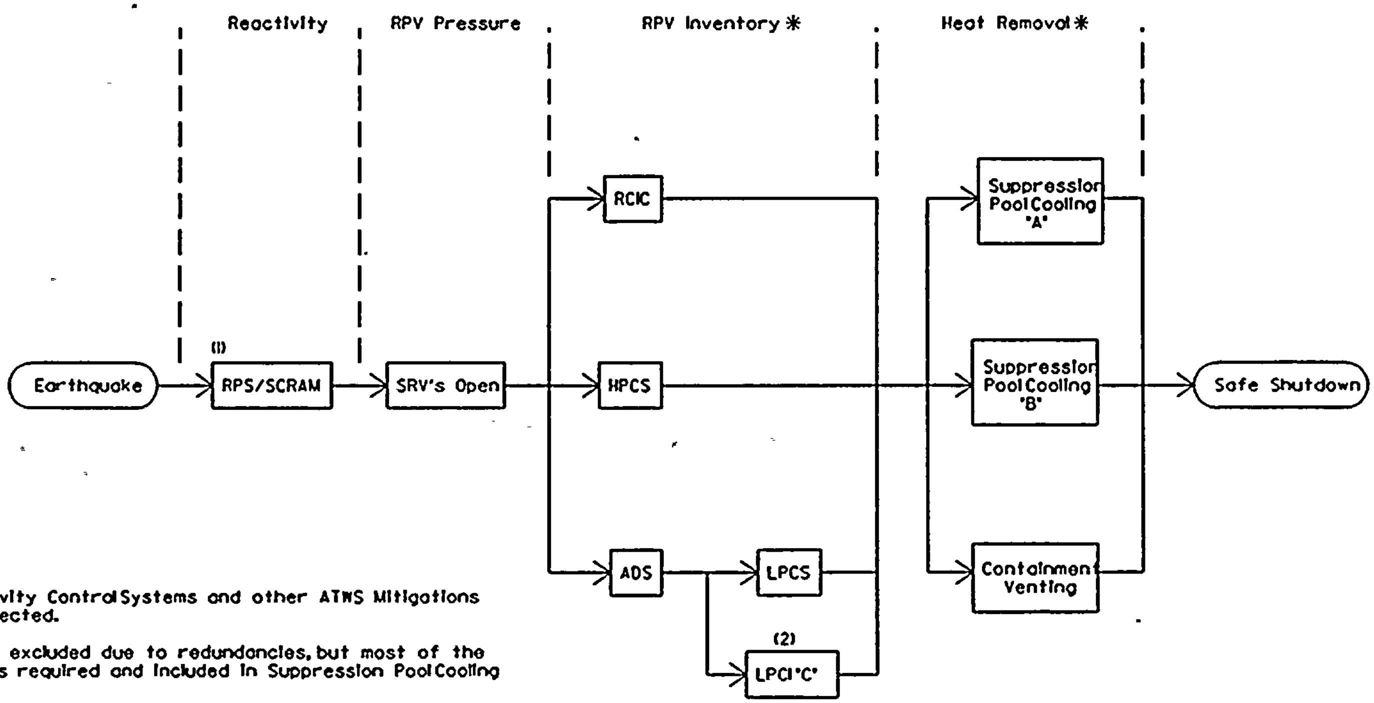
(5) Pump anchorage, equipment type, locations and structures are similar if not identical for these systems.

(6) Divisional UPS and ECCS initiations are required to support ADS, RCIC, LPCS and LPCI. UPS Divisions I & II and ECCS Divisions I & II are each identical and are treated as such for the seismic analysis.

(7) Long term high pressure Nitrogen appears necessary to keep SRVs open for 72 hours. RHR in shudown cooling mode is a possible alternative that is neglected.

(8) Containment venting was dropped from success during the seismic walkdown. Portions of N2 in the reactor building that supply CV are likely to leak and difficult to walkdown. Additionally, RHR appears adequate.

Figure 3.1-1
Functional Success Logic Diagram



NOTES: (1) Redundant Reactivity Control Systems and other ATWS Mitigations Systems are neglected.

(2) LPCI 'A' and 'B' are excluded due to redundancies, but most of the same equipment is required and included in Suppression Pool Cooling 'A' and 'B'.

✻ Feedwater and main condenser excluded because they are dependent on normal AC power. Also, service water and fire water cross connects to RHR for RPV inventory are neglected. Vapor Suppression is assumed necessary for the small LOCA scenario

Figure 3.1-2

Simplified Functional Success Diagram

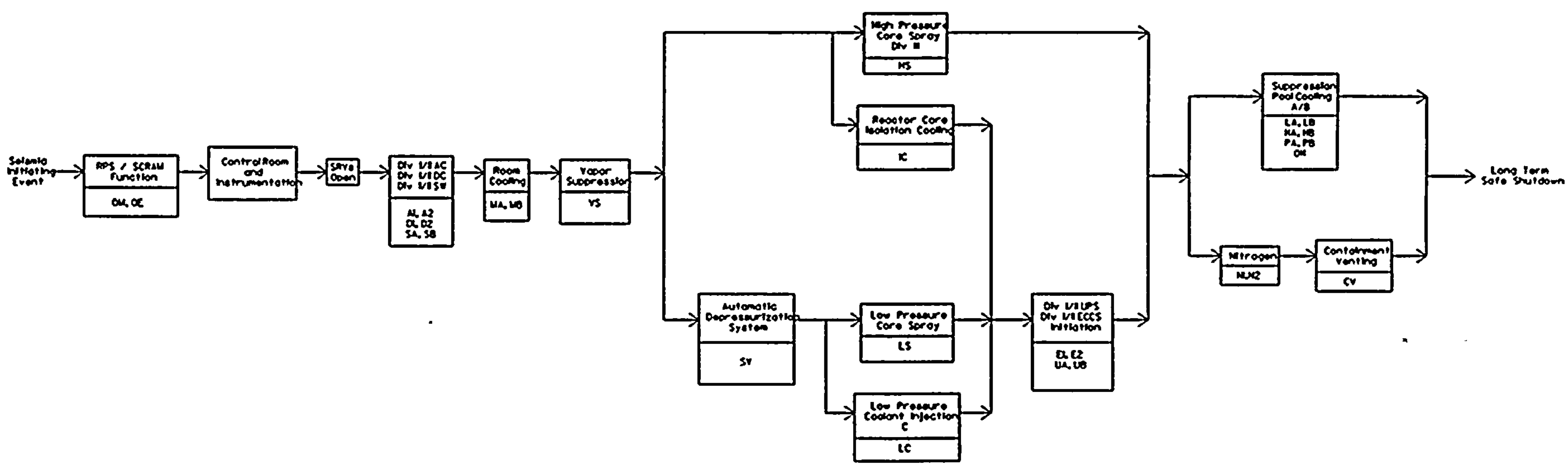


Figure 3.1-3
Functional Success Logic Diagram
Showing IPE Top Events

3.2 Seismic PRA

The NMP2 seismic PRA (SPRA) was performed for the following reasons:

- To put the seismic margins analysis (SMA) into quantitative perspective. The SPRA was developed to assess the frequency of core damage (CDF) and radiological releases utilizing the SMA results, NMP2 IPE, and seismic hazard frequencies developed by the industry for the NMP site.

- Provide additional public safety and economic risk insights. The SPRA can be incorporated into or combined with the IPE providing a more complete risk model and tool for decision making.

The key elements of a seismic PRA are similar to other external events in that the hazard (initiating event) must be analyzed and the capability (fragility) of structures, systems, and components relative to the hazard must also be assessed. As with other external events analysis, the location of equipment is important. Also, the internal events PRA is used to model seismic impact (fragility) on structures, systems, and components, and to perform point estimate quantification of seismic PRA sequences. Development of a simplified event sequence model (success diagram) can be used since certain simplifying assumptions that have no impact on the quantitative results can be made in a seismic PRA. Still, much of the details of the analysis are very different. The accident initiators are specific to seismic events, a more detailed definition of equipment is required from that identified in the internal events PRA, and the quantification procedure is unique. Also, the assessment of relay and contactor chatter impacts and evaluation of sensitive electrical equipment is important. The SMA considered the location of equipment, utilized the IPE to identify important structures, systems, and components, developed a simplified success diagram, and assessed contactor chatter and sensitive electrical equipment.

Thus, with the NMP2 IPE model, SMA completed, seismic hazards developed by EPRI and NRC, and insights observed from other industry seismic PRAs, the additional effort to perform this SPRA was comparatively insignificant. Since the frequency of major earthquakes at the NMP2 site (seismic hazard) is low and the plant HCLPF is high, the risk associated with seismic events was expected to be low. For this reason, simplifying conservative assumptions were made in this study to estimate risk.

The following summarizes the approach and steps required in developing the SPRA:

1. A seismic hazard is required to quantify the unconditional frequency of core damage and radiological releases. Both EPRI and NRC hazards[17,18] are used as initiating events in quantifying the model.

2. Seismic fragilities are required for structures, systems and components in the IPE model. The SMA for NMP2 (see Section 3.1) provides the necessary information with

one exception. A generic loss of offsite power fragility from the Seabrook Station seismic PRA[19] was used. Loss of offsite power was modeled with this fragility rather than always guaranteeing its failure. This was necessary to more realistically estimate the frequency of station blackout.

3. Nonseismic unavailabilities for those systems and functions that have relatively high unavailabilities is required to realistically assess accident scenarios. This input is available from the NMP2 IPE[1].

4. Using the inputs discussed above, an event tree model was developed from the IPE to generate and quantify accident sequences.

5. The model was quantified utilizing the same RISKMAN[5] computer code that contains the IPE. This code allows seismic hazards (initiating event) and fragilities (failure fractions of equipment in event tree top events) to be integrated into the event tree model and quantification.

The point estimated frequency of core damage and release types from this study are summarized below for the EPRI and NUREG hazards:

Core Damage Timing & Containment Status	Mean Annual Frequency	
	EPRI	NUREG
Late (loss of heat removal or injection)	5.9E-8	2.2E-7
Early - isolated containment (loss of injection)	3.2E-8	9.9E-8
Early - unisolated containment (loss of injection)	1.6E-7	9.0E-7
TOTAL	2.5E-7	1.2E-6

The table results display a relatively low risk from seismic events which is consistent with the insight that the frequency of a major earthquake is low at the NMP2 site and the HCLPF is high, on the order of 0.5g or greater. In addition, these results are conservative due to modeling assumptions and a conservative conversion of SMA HCLPFs to SPRA fragilities (see Section 3.2.4.3). The following summarizes the major contributors to the above results (the discussion is relative to the EPRI hazard with NUREG results in parentheses):

- All safety related equipment in the SMA success path were assessed to have a HCLPF of 0.5g or greater. This plant HCLPF is modeled as a direct cause of core damage (early - unisolated containment assumed) and its contribution to core damage frequency is 1.6E-7 (9.0E-7); about 60% of the total core damage frequency.

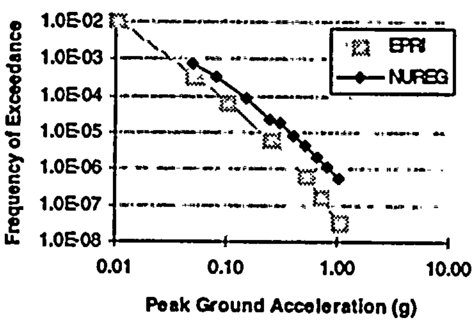
- Failure of nonsafety related (nonseismic qualified) high pressure nitrogen was assessed to have a HCLPF in the SMA of 0.23g. The SPRA model assumes that low pressure injection fails in the long term, if nitrogen fails, which is consistent with the SMA success path. The frequency of core damage associated with this fragility is 3.8E-8 (1.6E-7) which is less than the contribution from the plant HCLPF and comparable to station blackout results discussed below. These sequences dominate the "Late" end state in the above table. In any case, the model is conservative because the operators are likely to be on shutdown cooling before nitrogen is needed. Taking credit for the operators utilizing shutdown cooling would reduce this risk even further.

- Although offsite power was not included in the SMA, its fragility was included in this analysis to obtain a more realistic estimate of station blackout risk. The frequency of core damage from seismic failure of offsite power and subsequent station blackout from nonseismic failure of the emergency diesels is 3.4E-8 (1.0E-7). Station blackout is binned to the "Early" end state and there is no recovery modeled for station blackout. This is conservative since success of RCIC or HPCS could extend the timing to late and allow recovery, yet no credit was taken for this. On the other hand, there are relatively large uncertainties on recovery after a major earthquake.

With regard to the early unisolated end state, the plant HCLPF does dominate the results. However, the frequency is still relatively low and the results are conservative. Containment performance evaluations were included in the SMA studies which considered the primary containment structure, penetrations, piping and valves as well as LOCAs outside containment. The HCLPF for these structures and components is judged to be much higher than the 0.5g plant HCLPF value discussed in the above results. Our judgement is that containment failure is dominated by station blackout scenarios with unisolated penetrations. The annual frequency of these scenarios from this study is 3.7E-9 (1.1E-8) and includes credit for the operators locally isolating MOVs outside the primary containment. If this credit was removed (guaranteed failure), the frequency of an unisolated containment would be 3.7E-8 (1.1E-7). Thus, a more reasonable assessment of early large releases is expected to result in an order of magnitude reduction in the above results.

Core damage frequency is a factor of 5 higher when the NUREG hazard is used. The reason for this can be seen by comparing the mean hazard curves. The conclusion that seismic risk is low for NMP2 does not change regardless of which hazard is used.

EPRI and NUREG-1488 Mean Hazard Curves



3.2.1 Hazard Analysis

Seismic hazard is usually expressed in terms of the frequency distribution of the peak value of a ground-motion parameter (e.g., peak ground acceleration) at the site during a specified time interval.

The hazard estimate depends on uncertain estimates of attenuation, upperbound magnitudes, and the geometry of the postulated sources. Such uncertainties are included in the hazard analysis by assigning probabilities to alternative hypotheses about these parameters. A probability distribution for the frequency of occurrence is thereby developed. The annual frequency of exceeding the ground motion parameter, peak ground acceleration, is displayed in Figures 3.2-1 and 2 for NMP1.

The frequency of exceeding peak ground accelerations as proposed by EPRI and NRC[17, 18] for the NMP site were used as initiating events to quantify the unconditional frequency of core damage and radiological release. These hazards are presented in Figures 3.2-1 and 2. The hazards are discretized and used as initiating events in the SPRA accident sequence analysis. The following summarizes the point estimate initiating events as developed in the SPRA:

EPRI HAZARD			NUREG-1488 HAZARD		
Initiator	Acceleration Range (g)	Mean Annual Frequency	Initiator	Acceleration Range (g)	Mean Annual Frequency
SEIS1	0.01-0.05	1.46E-2	SEISA	0.08-0.15	2.62E-4
SEIS2	0.05-0.10	2.87E-4	SEISB	0.15-0.25	6.50E-5
SEIS3	0.10-0.25	6.61E-5	SEISC	0.25-0.31	5.00E-6
SEIS4	0.25-0.51	6.21E-6	SEISD	0.31-0.41	9.70E-6
SEIS5	0.51-0.71	5.10E-7	SEISE	0.41-0.66	6.20E-6
SEIS6	0.71-1.02	1.44E-7	SEISF	0.66-1.02	1.57E-6

The mean annual frequency for each acceleration range (initiator) is calculated by subtracting the upper range from the lower range frequency of exceedance value. For example, SEIS1 is calculated as follows from the Figure 3.2-1 mean values:

SEIS1 = (1.5E-2) - (3.6E-4) = 1.46E-2

3.2.2 Review of Plant Information and Walkdown

See Section 3.1.1

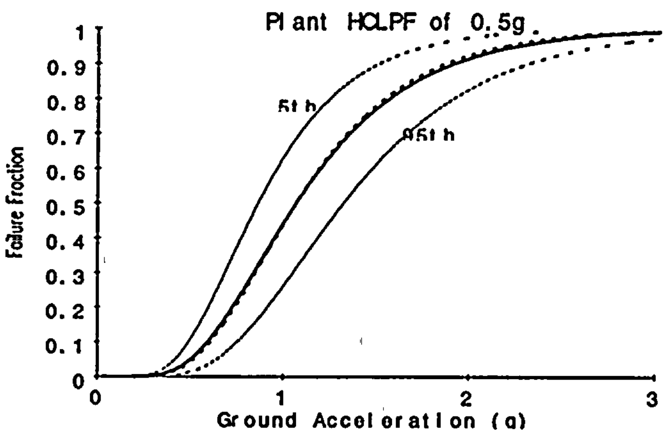
3.2.3 Analysis of Plant Systems and Structure Response

See Sections 3.1.2, 3.1.3 and 3.1.4.

3.2.4 Evaluation of Component Fragilities and Failure Modes

3.2.4.1 Seismic Fragility Analysis

The objective of the fragility evaluation is to estimate the ground acceleration capacity of a given component. This capacity is defined as the peak ground motion acceleration value at which the seismic response of a given component located at a specified point in the structure exceeds the component's resistance capacity, resulting in its failure. The ground acceleration capacity of the component is estimated using information on plant design bases, responses calculated at the design analysis stage, as-built dimensions, and material properties. Because there are many variables in the estimation of this ground acceleration capacity, component fragility is described with uncertainties.



This figure provides an example of how the results can be displayed as a family of fragility curves. The example component is the plant HCLPF (COMP1) from the SMA and described in Section 3.2.4.2.

Three of the curves can be thought of as representing a family of fragility curves where the percentiles indicate the level of confidence that for a given fraction of earthquakes, the component will fail at accelerations greater than indicated by the curve. The center curve is the median (50th percentile) fragility curve. The 5th and 95th percentile curves are also shown reflecting the uncertainty in the median curve. In addition, the mean curve which is calculated with a composite uncertainty (B_C) is shown in the figure as a solid line. The mathematical expressions for developing these curves and their relationships are explained further below. There actually exists a family of curves representing designated cumulative percentiles of confidence. Note that in the above figure, the median seismic capacity of COMP1 corresponds to the failure fraction 0.5 for the median fragility curve.

The above fragility curves can be developed from the best estimate seismic capacity (A_M) and its variabilities (B_U and B_R) using the following equation:

$$A = A_M * e^{(f * Bu + f' * Br)} \tag{1}$$

where

A is the ground acceleration corresponding to failure.

A_M is the best estimate of the median ground acceleration capacity.

f and f ' are the standard Gaussian random variables. In the above figure, the 5th, 50th, and 95th percentile curves are calculated by setting f ' to -1.645, 0.0, and 1.645, respectively, and varying f from -3.72 (corresponds to 1E-4 failure fraction) to 2.326 (corresponds to 0.99 failure fraction).

B_U is a logarithmic standard deviation representing uncertainties associated with the lack of knowledge such as analytical modeling assumptions, material strengths, damping, etc which could in many cases be reduced by additional study or testing.

B_R is a logarithmic standard deviation representing inherent randomness associated with earthquake characteristics such as variabilities in response spectra shapes & amplifications, duration, numbers & phasing of peak excitation cycles, etc which can not be significantly reduced by additional analysis or tests based on current state-of-the-art techniques.

From the above equation, fragility curves and the high confidence of low probability of failure (HCLPF) can be calculated and reported as shown in the above figure.

To calculate the high confidence of low probability of failure (HCLPF), f and f ' are set equal to -1.645 in Equation (1).

Another parameter used is the composite of uncertainty which is related to the above by the following equation:

$$B_C = (B_U^2 + B_R^2)^{1/2} \tag{2}$$

The B_C curve in the above figure is calculated from the following equation:

$$A = A_M * e^{f * Bc} \tag{3}$$

Point estimate quantification of a component failure fraction (probability of the standard, normal variate f, P(f)) is calculated from the mean fragility curve, equation (3), as follows:

$$P(f) = \text{Failure Fraction} = P(\ln (A/A_M)/B_C) \qquad (4)$$

Both the point estimate and the Monte Carlo options in RISKMAN use a piecewise integration algorithm for quantification of the failure fractions. This algorithm splits the range of acceleration values defined for a given initiating event into discrete subintervals, and computes a representative failure fraction for the range by weighting the failure fraction of each of the subintervals by the fraction of the initiating event frequency corresponding to the subintervals. For a single hazard curve and a single fragility curve, the failure fraction for a given initiating event (i.e., over a defined acceleration range) is calculated as follows:

$$FF = \Sigma\ [f(i)*h(i) / \Sigma h(i) \qquad (5)$$

where

FF = the conditional component failure fraction

f(i) = the conditional component failure fraction calculated at the upper boundary of subinterval "i". For the point estimate quantification option, f(i) is calculated as in equation (4) where f(i) = P(f).

h(i) = the seismic hazard frequency corresponding to the "ith" subinterval. As described in Section 3.2.1, h(i) is calculated by subtracting the exceedance frequency at the upper acceleration boundary of the subinterval from the exceedance frequency corresponding to the lower acceleration bin boundary. The exceedance frequencies used in this calculation must be interpolated from the user supplied points representing the hazard curve. Logarithmic interpolation is used for this calculation.

The point estimate option of RISKMAN does not use the mean hazard curve to compute the failure fractions. Instead, the code generates failure fractions based on each of the input hazard curves (and the mean fragility curve), and calculates the resultant point estimate failure fraction as the weighted average of the results obtained using the individual hazard curves.

The Monte Carlo calculation of failure fractions uses basically the same calculation method described above for the point estimate calculation. The difference is that, for each Monte Carlo trial, RISKMAN randomly chooses one of the user supplied hazard curves, and randomly selects one fragility curve from the family of fragility curves.

3.2.4.2 Summary of HCLPF Results From SMA

The NMP2 plant high confidence low probability of failure (HCLPF), as determined by the seismic margin assessment (SMA), is greater than 0.5g. With one exception, all structures, systems and components (SSC) identified in the SMA success diagram were evaluated to have a HCLPF value >0.5g. This exception is the nonsafety related high pressure nitrogen bottle supply to the safety relief valve storage tanks. This nitrogen supply was assumed to be required to keep the safety relief valves open in the long term (>24 hours after the seismic event) after emergency depressurization is required to provide low pressure ECCS makeup to the reactor vessel. This does not effect the SMA determined plant HCLPF because there are two redundant success paths (RCIC and HPCS) to the emergency depressurization and low pressure injection success path. Both of these redundant paths were assessed to have a HCLPF greater than 0.5g. However, the emergency depressurization and low pressure injection success path is also judged to have an effective HCLPF of 0.5g. The basis for this judgment is provided in the discussion below and the seismic probabilistic risk assessment (SPRA).

Nitrogen makeup is only required in the long term when, if at all possible, the plant would surely be shutdown in the RHR shutdown cooling mode (SDC) of operation. Although this was not explicitly modeled in the SMA success diagram, RHR in the suppression pool cooling mode (SPC) of operation was modeled which shares many of the components required in the SDC mode. In addition, the SMA success diagram development recognized the SDC mode as a possibility and identified the extra components that would have to be considered. Most of the components are safety related and similar to those evaluated for the SPC mode. Utilizing shutdown cooling does require that an isolation valve in each reactor recirculation loop be closed to force return flow through the jet pumps and into the core. Because these valves are powered by 2NHS-MCC011 and MCC012, which are supplied from offsite power, they are not expected to be operable after a seismic event. However, these MCCs can be fed from a diesel generator via a cross feed arrangement. Shutdown cooling is not needed within the first 24 hours and because it is not needed there is ample time for operator action to realign the electrical buses. In addition, aligning shutdown cooling, without isolating valves in the reactor recirculation loops, may provide adequate heat removal (must maintain pressure below 128 psig), although analyses that demonstrates that natural circulation between the reactor vessel and the cooled recirculation loop can maintain pressure below 128 psig is not available.

Risk insights on the above SMA conclusions are provided in this study.

3.2.4.3 Seismic Fragilities Used in SPRA

The SMA provided the following two 84th percentile confidence level HCLPF values with a B_C of 0.46:

$HCLPF_{84}$ = 0.50g for all safety related components in the SMA success path

$HCLPF_{84}$ = 0.23g for the high pressure nitrogen supply outdoors

To convert these SMA CDFM (conservative deterministic failure margin) values to median fragilities for the SPRA, the $HCLPF_{84}$ is multiplied by 2.13 to obtain the medium value, A_M. The basis for this conversion is discussed below:

According to EPRI Research Report TR-103595, "Methodology for Developing Seismic Fragilities," Final Report, June 1994, the median fragility, A_M, can be expressed by

$$A_M = HCLPF_{50} * e^{2.3Bc} \tag{6}$$

where B_R and B_U have been slightly conservatively combined into B_C. The $HCLPF_{50}$ notation is used to differentiate this HCLPF definition from the one calculated in a SMA using the conservative deterministic margin method (CDFM). In the CDFM method the HCLPF is referred to as the $HCLPF_{84}$ since it is defined to correspond to the ground motion reported at the 84% nonexceedance probability level. This is in contract to the SPRA $HCLPF_{50}$ that corresponds to the ground motion at the median probability level. The relationship between the two HCLPF definitions is given by the following equation:

$$HCLPF_{84} = e^{Brs} * HCLPF_{50} \tag{7}$$

where B_{RS} is the combined logarithmic standard deviation for the horizontal component response spectrum shape basic variable. It is a SRSS (square root of the sum of the squares) combination of the B_R and B_U values.

Using equations (6) and (7), with $B_C = 0.46$ and $B_{RS} = 0.30$, the median fragility can be converted from the $HCLPF_{84}$ as follows:

$$A_M = 2.13 * HCLPF_{84} \tag{8}$$

The following table summarizes the seismic fragilities used in the SPRA model:

Comp	Description	Fragility				
		$HCLPF_{50}$	B_C	A_M	B_U	B_R
COMP1	Represents SMA HCLPF	0.42	0.46	1.07	0.44	0.13
COMP2	High pressure nitrogen	0.18	0.46	0.49	0.44	0.13
COMP3	Loss of offsite power	0.12	0.46	0.30	0.44	0.13

The two SMA fragilities in the above table (COMP1 and COMP2) were still derived conservatively because they have not been scaled to consider differences in peak spectral values relative to the reference PGA (peak ground acceleration). A more realistic development of the each fragility is discussed below and later in this section the significance of this conservatism is discussed:

COMP1 (Components Screened at SMA HCLPF of 0.5g)
For the screened out components in the SMA, most of these items were screened out based on EPRI[11] Tables 2.3 and 2.4, the CDFM is 1.2g in reference to the peak of the spectra. To scale the peak spectral values back to the reference PGA, the 10000-year 50% spectral shapes from EPRI[17] and LLNL[18] results in the following table are used:

Frequency (Hz)	NUREG-1488 (g)	EPRI (g)
1	0.023	0.013
2.5	0.068	0.037
5	0.099	0.070
10	0.141	0.107
25	0.136	0.139
PGA	0.083	0.073

Using the peak spectral value as the basis of comparison, the median fragility for components at the screening value can be estimated as follows:

NUREG $A_M = 2.13 * 1.2 * 0.083/0.141 = 1.5g$

EPRI $A_M = 2.13 * 1.2 * 0.073/0.139 = 1.34g$

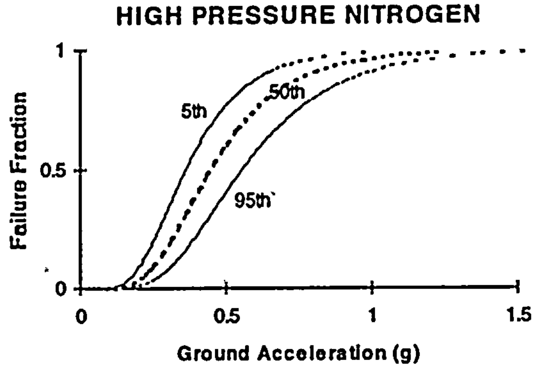
COMP2 (High Pressure Nitrogen, SMA HCLPF of 0.23g)
The HCLPF is governed be the neighboring liquid nitrogen tanks due to seismic interaction. The median fragility can be estimated as follows:

NUREG $A_M = 2.13 * 0.23 * 2.12 * 0.083/0.141 = 0.61g$

EPRI $A_M = 2.13 * 0.23 * 2.12 * 0.073/0.139 = 0.55g$

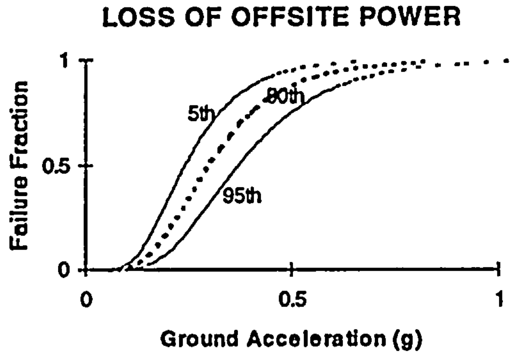
The factor 2.12 is the spectral peak to PGA ratio of the NUREG-0098 50% spectral shape[20].

COMP1 failure is modeled as causing core damage and represents the SMA conclusion for NMP2 that all safety related structures, systems, and components identified in the SMA success diagram have a $HCLPF_{84}$ of 0.5g or greater. Although this assumption is conservative, it does represent the best knowledge available on the fragility of the plant. The results of this analysis provides insights on the potential order of magnitude impact of this assumption. The COMP1 fragility curve is provided in Section 3.2.4.1.



The fragility for high pressure nitrogen (COMP2) is based on the SMA results and is assumed to result in an initiating event even if there is no loss of offsite power. It is conservatively assumed that all nitrogen and instrument air fails resulting in loss of feedwater and the main condenser. In addition, failure of high pressure nitrogen results in failure of low pressure injection (safety relief valves eventually close) if the operators do not have the plant on shutdown cooling in time.

The fragility for loss of the offsite power (COMP3) was not provided in the SMA because the success diagram was developed assuming that offsite power was unavailable (offsite power was recognized to have a relatively low fragility relative to other components). Since offsite power was known to have a relatively low fragility and the purpose of the SMA was to assess the HCLPF of more robust success paths, there was no need to evaluate this system and the numerous systems that depend on offsite power as potential success paths. However, in a SPRA it is necessary to model a fragility for offsite power to realistically model station blackout risk. Otherwise, if we assumed loss of offsite power without a fragility, this would result in an unrealistically high core damage frequency from station blackout. The above fragility is similar to that used in Seabrook Station seismic PRA[19] and other PRAs.



Conditional and unconditional frequency of failure are presented in the tables below for the three above fragilities at each discrete hazard initiating event frequency described in Section 3.2.1. The conditional failure fraction is calculated as described in Section 3.2.4.1 and does not include the hazard frequency. The unconditional frequency calculation accounts for the hazard frequency by multiplying the conditional failure fraction times the hazard frequency. The following provides an example unconditional calculation for COMP1:

> Unconditional COMP1 at SEIS1 = Conditional COMP1 at SEIS1* SEIS1 Frequency = 2.9E-7 failure fraction (see table below) * 1.46E-2/yr (see Section 3.2.1) = 4.2E-9/yr

Component Conditional Failure Fractions Based on EPRI Hazard							
Component	SEIS1	SEIS2	SEIS3	SEIS4	SEIS5	SEIS6	TOTAL
COMP1	2.9E-7	2.9E-7	5.6E-5	9.2E-3	0.10	0.29	-
COMP2	2.9E-7	6.6E-5	1.5E-2	0.26	0.71	0.90	-
COMP3	1.1E-6	1.4E-3	8.1E-2	0.57	0.92	0.98	-
Component Unconditional Failure Frequencies Based on EPRI Hazard							
COMP1	4.2E-9	8.2E-11	3.7E-9	5.7E-8	5.1E-8	4.1E-8	1.6E-7
COMP2	4.2E-9	1.9E-8	9.9E-7	1.6E-6	3.6E-7	1.3E-7	3.2E-6
COMP3	1.6E-8	4.0E-7	5.4E-6	3.6E-6	4.7E-7	1.4E-7	9.9E-6

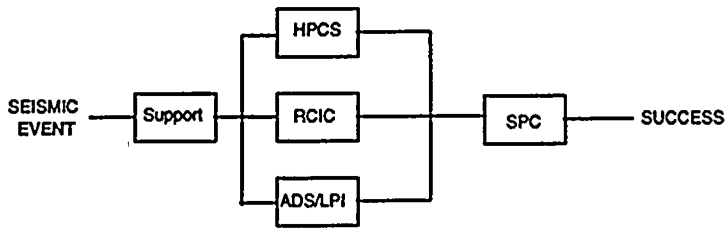
From the above unconditional results, we can see that the frequency of core damage is going to be relatively low in the SPRA. In order for COMP2 (nitrogen) failure to cause core damage, HPCS and RCIC must fail and the operators must fail to get to shutdown cooling. In order for COMP3 (offsite power) failure to cause core damage, both emergency diesels must fail.

Similar results are provided below for the NUREG hazard:

Component Conditional Failure Fractions Based on NUREG Hazard							
Component	SEISA	SEISB	SEISC	SEISD	SEISE	SEISF	TOTAL
COMP1	1.2E-6	1.5E-4	1.8E-3	8.6E-3	5.8E-2	0.27	-
COMP2	1.6E-3	3.5E-2	0.15	0.30	0.59	0.89	-
COMP3	1.7E-2	0.17	0.44	0.64	0.86	0.98	-
Component Unconditional Failure Frequencies Based on NUREG Hazard							
COMP1	3.2E-10	9.5E-9	9.2E-9	8.4E-8	3.6E-7	4.2E-7	8.8E-7
COMP2	4.3E-7	2.3E-6	7.5E-7	2.9E-6	3.4E-6	1.4E-6	1.1E-5
COMP3	4.5E-6	1.1E-5	2.2E-6	6.2E-6	5.3E-6	1.5E-6	3.0E-5

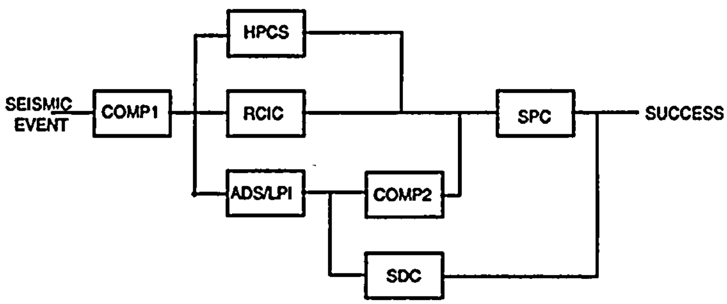
3.2.5 Analysis of Plant Systems and Sequences

3.2.5.1 Plant Response Model Development



A simplified representation of the SMA success path is provided here. All the support systems, structures, and instrumentation in the SMA success path that are required to maintain reactor inventory control and heat removal are represented by the "Support" block for simplification. The "HPCS" and "RCIC" blocks represent the high pressure core spray (reactor inventory control) and reactor core isolation cooling (reactor inventory control) systems, respectively. ADS/LPI represents emergency depressurization with the safety relief valves and low pressure injection with low pressure core spray or low pressure coolant injection "C" (reactor inventory control). SPC represents residual heat removal "A" or "B" in the suppression pool cooling mode (heat removal).

The SMA success path assumed that high pressure nitrogen was required to keep the safety relief valves open in the long term (>24 hours after the seismic event) if both HPCS and RCIC fail. In addition, the SMA success path did not explicitly model the shutdown cooling mode of RHR which should have a high likelihood of success (see Section 3.1.2). The simplified success diagram below incorporates these considerations and the SMA fragilities.



COMP1 and COMP2 represent fragilities for the plant HCLPF and high pressure nitrogen as described in the previous section. SDC represents the probability that RHR shutdown cooling is attained before the need for long term nitrogen. SDC is used for sensitivity studies in assessing the importance of COMP2. For the purposes of simplification, support system requirements are not explicitly shown in the above figure. The incorporation of support systems, including the offsite power fragility (COMP3) and other considerations into the final accident sequence model (Figure 3.2-3) is described below.

The SPRA model treats a typical plant trip without seismic failure of a component as a success sequence. This is a reasonable assumption because the frequency of a plant scram or turbine trip due to an earthquake with offsite power and the balance of plant equipment available is bounded by the NMP2 IPE (e.g., seismic causes for these initiators are much less frequent). Consistent with other SPRAs, loss of feedwater, main condenser and their support systems is assumed to be incorporated within the loss of offsite power fragility. This is also a reasonable assumption, since offsite power has been assessed to be the weak link and this is based on actual earthquake experience.

In a seismic PRA, there is no need to model nonseismic unavailabilities for systems and functions that are highly reliable. Because of the low frequency of consequential earthquake initiating events (i.e, the mean frequency of exceeding a 0.1g earthquake is on the order of 1E-4/year at NMP2), the SPRA accident sequence model needs to consider seismic fragilities and only nonseismic unavailabilities of systems and functions with high unavailabilities. The following general rules were used to determine which nonseismic systems and functions to model in the SPRA:

- IPE event tree top event unavailabilities greater than 1E-2 were retained in the SPRA. Top event unavailabilities less than 1E-2 were neglected if there is functional redundancy with another top event. This ensures that the frequency of any neglected sequences is less than 1E-8/year.

- If there is limited redundancy associated with an event tree top event and/or its failure results in the failure of several top events due to dependencies, the unavailability must be less than 1E-4 to be neglected. This ensures that the frequency of any neglected sequences is less than 1E-8/year.

Thus, the seismic model developed here is a simplified version of the IPE. This simplified model improves the communication of important aspects of the modeling, and allows quantification and sensitivity studies to be performed efficiently. This simplified model can be incorporated directly into the existing IPE event trees utilizing revised top event rules and split fractions. The quantitative results and conclusions will not change significantly.

The following nonseismic unavailabilities from the IPE were judged to potentially influence the seismic PRA results and thus were included in the model:

- Emergency AC power given loss of offsite power. AC and DC power support systems are very reliable when offsite power is available and are not significant to seismic risk under these conditions. Given loss of offsite power, the emergency diesels dominate the unavailability of emergency AC. The reliability of other AC power components, DC power, and other support systems is high in comparison to the diesels.

- HPCS and RCIC. These two systems provide redundancy to the emergency depressurization/low pressure injection success path. Since both of these systems have relatively high unavailabilities, they are included in the SPRA model.

- ADS/LPI. This function is modeled because operator action to emergency depressurize the reactor is required and assumed to dominate failure. The reliability of the safety relief valves is high and there are redundant low pressure injection systems.

- Nitrogen. Since the long term success of ADS/LPI depends on nitrogen and its fragility was found to be less than the 0.5g screening level, this is modeled.

- SPC. The suppression pool cooling (SPC) mode of RHR is modeled because its unavailability just exceeds the criteria set above.

- SDC. The shutdown cooling (SDC) mode of RHR was modeled in the event tree and success logic, but was quantitatively set to guaranteed failure in the baseline model. Thus, the model allows evaluation of the importance and sensitivity of crediting the SDC function. Specifically, if high pressure nitrogen fails, the operators could align SDC in the long term before the primary nitrogen source is deleted; SRVs close and low pressure injection is lost. Aligning SDC implies that SRVs and nitrogen are not required for success in the long term (>24 hours).

- Containment isolation. The containment isolation system is important to early large releases and meets the criteria for inclusion in the model. Note that structural failure of the containment can be considered to be included in the plant HCLPF fragility, although this is conservative.

No credit is taken in the model for containment venting, however, this is expected to be an insignificant conservatism. Based on the above, the event tree model in Figure 3.2-3 was developed to quantify accident scenarios initiated by seismic events. The event tree, accident sequence quantification, and results are described in the next section.

3.2.5.2 Accident Sequence Quantification

The event tree, Figure 3.2-3, was quantified utilizing the fragilities and IPE nonseismic unavailabilities as described in the previous sections. The master frequency file is provided in Tables 3.2-1A and 1B for the EPRI and NUREG inputs, respectively. The only differences between these input files are associated with the component fragility split fractions for event tree top events COMP1, COMP2, and COMP3. These values are different only because the seismic hazard inputs resulted in different hazard boundary definitions.

To fully understand the accident sequence model logic and success criteria , the event tree structure, split fraction rules, and binning logic should be reviewed. The split fraction rules (logic) and binning rules are included with Figure 3.2-3, the event tree. The following summarizes the success criteria, where both reactor inventory control (INJ) and heat removal (DHR) functions must be satisfied:

Reactor inventory control (INJ)

- HPCS (top event HS) or

- RCIC (top event IC) or

- Reactor depressurization with low pressure injection (top event OD) and either high pressure nitrogen to keep SRVs open in long term (top event N2 and COMP2) or the operators have to align shutdown cooling mode of RHR (top event SD) before the SRV nitrogen supply expires. Top event SD was quantitatively set to failure consistent with the SMA success diagram.

Heat Removal (DHR)

- RHR "A" (top event LA) in the suppression pool cooling mode or

- RHR "B" (top event LB) in the suppression pool cooling mode or

- Reactor depressurization with low pressure injection (top event OD) and the operators align shutdown cooling mode of RHR (top event SD) before the SRV nitrogen supply expires. In the event tree structure, this is only allowed if HPCS (HS) and RCIC (IC) and nitrogen fails (N2 or COMP2 fails). However, top event SD was quantitatively set to failure consistent with the SMA success diagram.

In the event tree structure, there are three cases where the above systems and functions are bypassed, and because of this, the logic for the above functions is not satisfied. These are discussed below:

- When all three fragilities are successful (COMP1, COMP2 and COMP3), this first sequence is binned to success. As described in the previous section, this is a reasonable assumption because the frequency of a plant scram or turbine trip due to an earthquake with offsite power and balance of plant equipment available is bounded by the NMP2 IPE (e.g., seismic causes for these initiators are much less frequent). Consistent with other SPRAs, loss of feedwater, main condenser and their support systems is assumed to be incorporated within the loss of offsite power fragility. This is also a reasonable assumption, since offsite power has been assessed to be the weak link and this is based on actual earthquake experience.

- Station blackout sequences (failure of COMP3 and A1 and A2) are binned directly to early core damage. Only the status of containment isolation (top event IS) is questioned to determine whether an early release occurs. This is conservative since success of RCIC or HPCS could extend the timing to late and allow recovery, yet no credit was taken for this.

- Failure of the plant HCLPF (COMP1) is binned directly to early core damage with a failed containment. COMP1 represents the SMA conclusion that all safety related equipment in the SMA success path were assessed to have a HCLPF of 0.5g or greater. This modeling is conservative especially for early release. Containment performance evaluations were included in the SMA studies which considered the primary containment structure, penetrations, piping and valves as well as LOCAs outside containment. The HCLPF for these structures and components is judged to be much higher than the 0.5g plant HCLPF value.

The following summarizes the core damage end states:

- **LATE** - This end state is used when inventory control is initially successful and heat removal is unavailable. RHR shutdown cooling (SD) or RHR suppression pool cooling (LA*LB) failure lead to loss of heat removal. These scenarios are assumed to lead to containment overpressure failure modes modeled in the IPE.

- **EI** - This end state is used when inventory control fails and containment isolation (IS) is successful. High and low pressure injection failure (HS*IC*OD failure) or station blackout (A1*A2 failure) leads to loss of all injection.

- **EO** - This end state is used when inventory control fails and containment isolation (IS) fails. High and low pressure injection failure (HS*IC*OD failure) or station blackout (A1*A2 failure) leads to loss of all injection. This end state is also used when the plant HCLPF (COMP1) fails.

The results of the model quantification are shown in Section 1 for the above end states. The dominant sequences (>1E-9/year) are presented in Table 3.2-2 for total core damage frequency. Event tree top event importance values are provided in Table 3.2-3.

The end states used in this model and described above are somewhat simplistic from those used in the IPE and the model used here does not include the IPE Level 2 event trees. The significance of these considerations are discussed below:

- Assuming containment overpressure failures in the IPE for the "LATE" endstate without recovery of heat removal in the Level 2 model is reasonable for seismic events, but conservative. Also, the Level 1 model takes no credit for continued injection during and after containment failure as a success. Conditional probabilities of containment failure locations and sizes in the Level 2 model could be developed from the IPE, but was not done because of the low frequency.

- The "EI" endstate is potentially optimistic because it neglects the conditional probability of an early or late containment failure in the Level 2 model even though containment isolation is successful. Conditional probabilities for these failures could be developed from the IPE. This was not done here because of the low frequency. Even if the conditional probability of early large containment failure was assumed to be 1.0, the frequency is relatively low.

- Assuming an early large release for the "EO" endstate without recovery in the Level 2 model is reasonable for seismic events, but conservative. A more detailed analysis could be considered consistent with the IPE. This was not done because of the low frequency.

Human Response

Consistent with the IPE and EOPs, there are human actions considered relatively important to the accident sequence model in this study and described below:

- Operator actions associated with controlling RCIC and/or HPCS is assumed successful in the IPE after two or three cycles from low level start to high level trip and back to low level start again. Given the time it takes for these cycles and the relatively high unavailabilities for these systems, this is considered reasonable for seismic events as well.

- Operator actions to depressurize the reactor, given loss of RCIC and HPCS, is modeled in top event OD. It was assumed in the IPE that the operators inhibited ADS (automatic depressurization) and then, had to manually open the safety relief valves when level reached top of active fuel. The reliability of ADS and injection systems is sufficiently high such that if the operators failed to disable ADS, core damage frequency would not change significantly. In fact, it is assumed that this treatment is as conservative for seismic events as it is with the IPE. The operator failure probability used for OD in this analysis is 1E-2 versus 1E-3 used in the IPE.

- Long term alignment of RHR to suppression pool cooling is not explicitly modeled. This was considered to be a very reliable operator action in the IPE due to the significant time available, limited actions required, and redundant cues available to the operators in the EOPs. The probability of failure in the IPE is 1E-5. The total unavailability of RHR (failure of top events LA and LB) with all support systems available is 5E-4, which has the equivalent impact as the operator failure. This value is assumed to reasonably envelop operator errors even for seismic events.

- The containment isolation (IS) model includes an operator action to isolate outside motor operated valves, given a station blackout. The probability of failure in the IPE and in this study is 0.11. Note that even if no credit is given to the operator for containment isolation, the early unisolated containment endstate is not significantly increased.

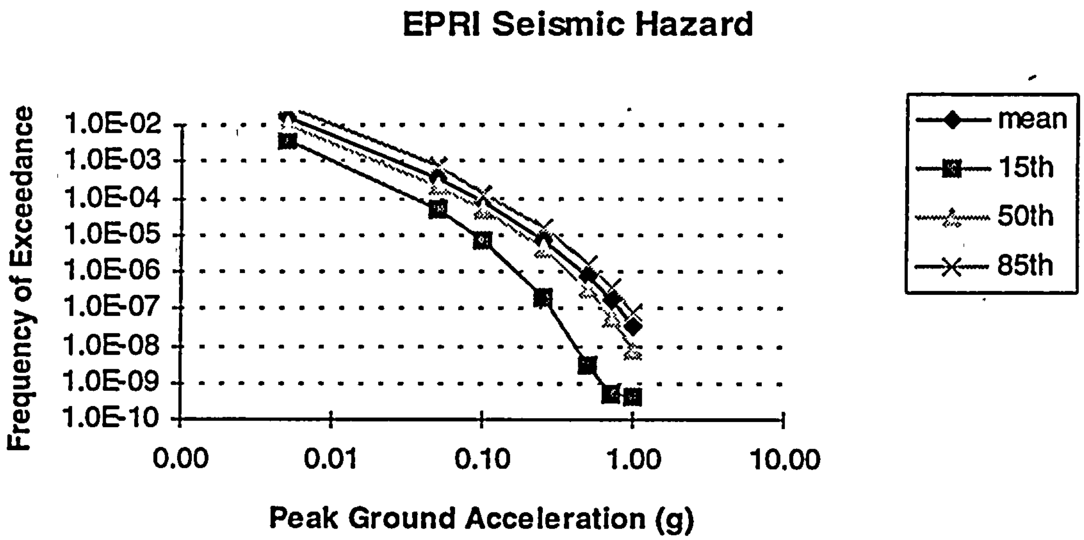
The importance of operator actions and other event tree top events can be seen from reviewing Table 3.2-3.

3.2.6 Analysis of Containment Performance

As described in Section 3.1, a plant HCLPF of 0.5g or greater is required to impact containment performance. Also, Section 3.1.5 describes reviews perform to identify the potential for interfacing LOCAs.

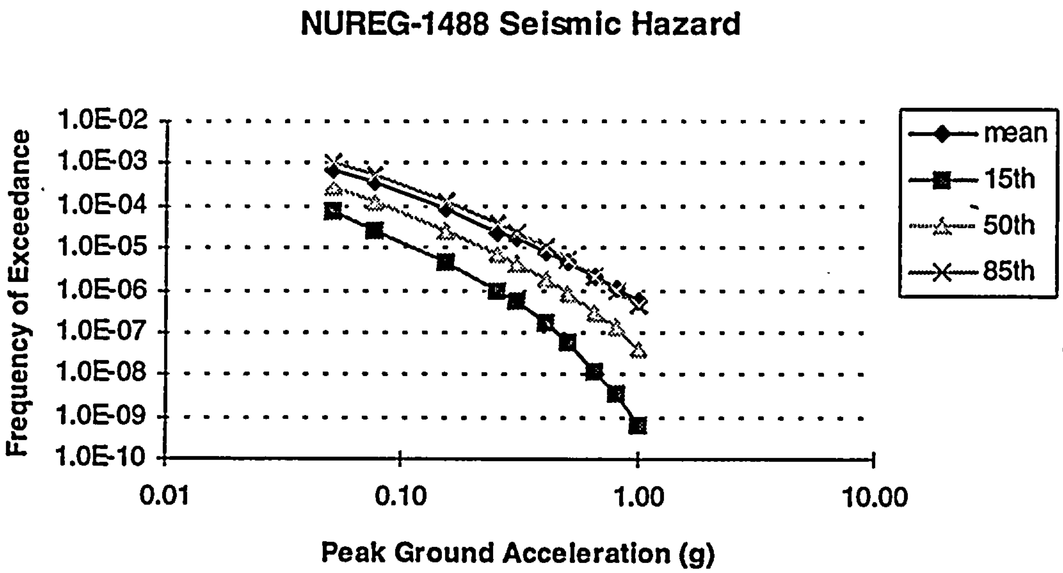
With regard to the early unisolated end state in the SPRA, the plant HCLPF does dominate the results. However, the frequency is still relatively low and the results are conservative. Containment performance evaluations were included in the SMA studies which considered the primary containment structure, penetrations, piping and valves as well as LOCAs outside containment. The HCLPF for these structures and components is judged to be much higher than the 0.5g plant HCLPF value discussed in the above results. Our judgement is that containment failure is dominated by station blackout scenarios with unisolated penetrations. The annual frequency of these scenarios from this study is 3.7E-9 (1.1E-8) and includes credit for the operators locally isolating MOVs outside the primary containment. If this credit was removed (guaranteed failure), the frequency of an unisolated containment would be 3.7E-8 (1.1E-7). Thus, a more reasonable assessment of early large releases is expected to result in a major reduction in the quantitative results displayed in Section 3.2.1.

Figure 3.2-1



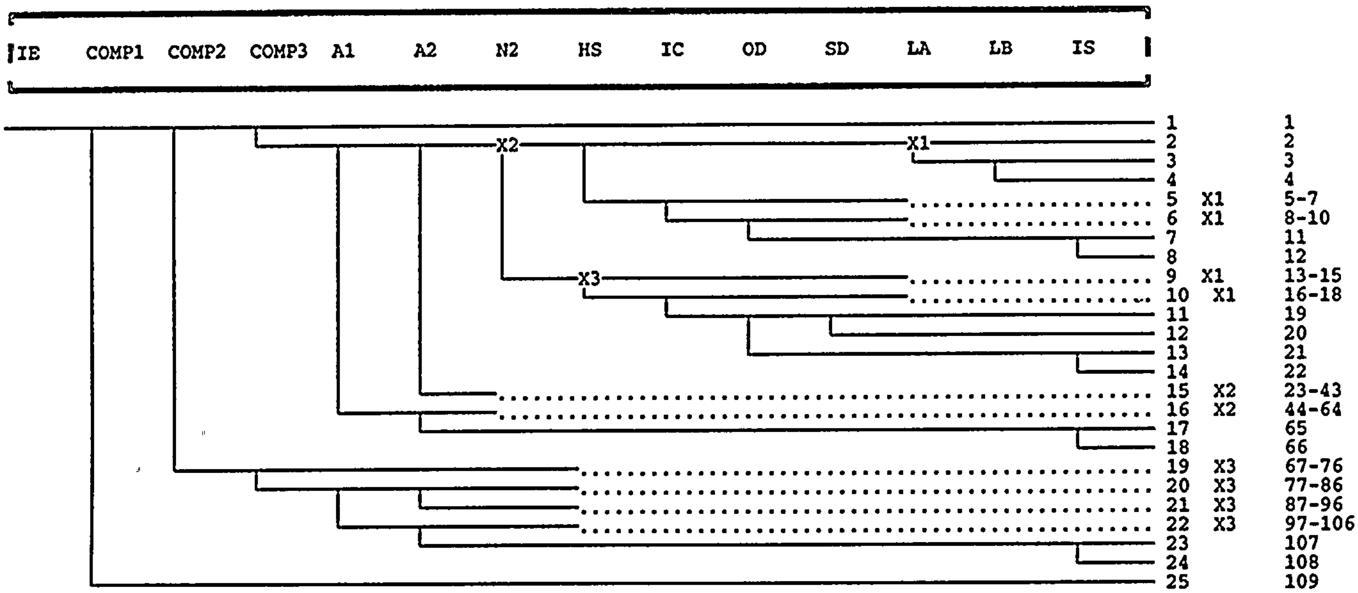
cm/sec2	g(x32.2ft/sec^2)	mean	15th	50th	85th
5	0.01	1.5E-02	3.5E-03	9.8E-03	3.1E-02
50	0.05	3.6E-04	4.7E-05	2.1E-04	7.3E-04
100	0.10	7.3E-05	6.6E-06	5.0E-05	1.3E-04
250	0.25	6.9E-06	1.9E-07	4.0E-06	1.5E-05
500	0.51	6.9E-07	3.1E-09	3.0E-07	1.6E-06
700	0.71	1.8E-07	5.3E-10	5.9E-08	3.7E-07
1000	1.02	3.6E-08	4.0E-10	7.6E-09	7.0E-08

Figure 3.2-2



cm/sec2	g(x32.2ft/sec^2)	mean	15th	50th	85th
50	0.05	7.3E-04	7.0E-05	2.7E-04	1.1E-03
75	0.08	3.5E-04	2.7E-05	1.2E-04	5.1E-04
150	0.15	8.8E-05	4.9E-06	2.5E-05	1.3E-04
250	0.25	2.7E-05	1.0E-06	6.7E-06	3.7E-05
300	0.31	1.8E-05	5.3E-07	4.1E-06	2.2E-05
400	0.41	8.3E-06	1.7E-07	1.7E-06	9.8E-06
500	0.51	4.5E-06	5.5E-08	7.8E-07	5.0E-06
650	0.66	2.1E-06	1.2E-08	2.8E-07	2.1E-06
800	0.82	1.1E-06	3.4E-09	1.2E-07	1.0E-06
1000	1.02	5.3E-07	6.2E-10	4.1E-08	4.4E-07

FIGURE 3.2-3
Seismic PRA Event Tree Model



Top Event	Top Event Description
IE	Initiating Event
COMP1	SMA PLANT HCLPF FRAGILITY
COMP2	HIGH PRESSURE NITROGEN FRAGILITY
COMP3	OFFSITE POWER FRAGILITY
A1	DIV I EMERGENCY DIESEL
A2	DIV II EMERGENCY DIESEL
N2	NITROGEN SUPPLY FOR VENTING
HS	HPCS
IC	RCIC
OD	OPERATOR DEPRESSURIZES/LPI
SD	SHUTDOWN COOLING
LA	DIV I RHR SUPPRESSION POOL COOLING
LB	DIV II RHR SUPPROESSION POOL COOLING
IS	CONTAINMENT ISOLATED

Figure 3.2-3 Event Tree Split Fraction Rules

Split Fraction	Split Fraction Logic (Rules)
COMP11	INIT=SEIS1+INIT=SEISA
COMP12	INIT=SEIS2+INIT=SEISB
COMP13	INIT=SEIS3+INIT=SEISC
COMP14	INIT=SEIS4+INIT=SEISD
COMP15	INIT=SEIS5+INIT=SEISE
COMP16	INIT=SEIS6+INIT=SEISF
COMP21	INIT=SEIS1+INIT=SEISA
COMP22	INIT=SEIS2+INIT=SEISB
COMP23	INIT=SEIS3+INIT=SEISC
COMP24	INIT=SEIS4+INIT=SEISD
COMP25	INIT=SEIS5+INIT=SEISE
COMP26	INIT=SEIS6+INIT=SEISF
COMP31	INIT=SEIS1+INIT=SEISA
COMP32	INIT=SEIS2+INIT=SEISB
COMP33	INIT=SEIS3+INIT=SEISC
COMP34	INIT=SEIS4+INIT=SEISD
COMP35	INIT=SEIS5+INIT=SEISE
COMP36	INIT=SEIS6+INIT=SEISF
A12	1
A24	A1=S
A28	1
N23	1
HS1	COMP3=S
HS2	1
IC1	1
OD1	1
SD1	1
LAF	A1=F
LA1	1
LBF	A2=F
LB3	A1=F
LB1	LA=S
LBA	1
IS1	A1=S*A2=S
IS2	A1=S+A2=S
IS3	1

Figure 3.2-3 Event Tree Binning Rules

Bin	Binning Rules
	INJ:= HS=S + IC=S + OD=S*(N2=S+SD=S)
	DHR:= OD=S*SD=S + LA=S + LB=S
SUCCESS	COMP1=S*COMP2=S*COMP3=S + INJ*DHR
LATE	SD=F + LB=F
EI	(OD=F + A1=F*A2=F)*IS=S
EO	IS=F + COMP1=F
DEFAULT	1

Table 3.2-1A
Master Frequency File (EPRI)

SF Name	Top Event	SF Value	Split Fraction Description
A12	A1	5.30E-02	DIV I AC POWER GIVEN LOSP
A24	A2	5.20E-02	DIV II AC POWER GIVEN LOSP & A1 SUCCESS
A28	A2	6.50E-02	DIV II AC POWER GIVEN LOSP & A1 FAILURE
COMP11	COMP1	2.90E-07	SEIS1, g Levels: .01 to .05
COMP12	COMP1	2.90E-07	SEIS2, g Levels: .05 to .1
COMP13	COMP1	5.60E-05	SEIS3, g Levels: .1 to .25
COMP14	COMP1	9.20E-03	SEIS4, g Levels: .25 to .51
COMP15	COMP1	1.00E-01	SEIS5, g Levels: .51 to .71
COMP16	COMP1	2.90E-01	SEIS6, g Levels: .71 to 1.02
COMP21	COMP2	2.90E-07	SEIS1, g Levels: .01 to .05
COMP22	COMP2	6.60E-05	SEIS2, g Levels: .05 to .1
COMP23	COMP2	1.50E-02	SEIS3, g Levels: .1 to .25
COMP24	COMP2	2.60E-01	SEIS4, g Levels: .25 to .51
COMP25	COMP2	7.60E-01	SEIS5, g Levels: .51 to .71
COMP26	COMP2	9.00E-01	SEIS6, g Levels: .71 to 1.02
COMP31	COMP3	1.10E-06	SEIS1, g Levels: .01 to .05
COMP32	COMP3	1.40E-03	SEIS2, g Levels: .05 to .1
COMP33	COMP3	8.10E-02	SEIS3, g Levels: .1 to .25
COMP34	COMP3	5.70E-01	SEIS4, g Levels: .25 to .51
COMP35	COMP3	9.20E-01	SEIS5, g Levels: .51 to .71
COMP36	COMP3	9.80E-01	SEIS6, g Levels: .71 to 1.02
HS1	HS	2.80E-02	HPCS - ALL SUPPORT AVAIL
HS2	HS	1.40E-01	HPCS - LOSP
IC1	IC	1.60E-01	RCIC
IS1	IS	5.30E-03	CONTAINMENT ISOLATION - ALL SUPPORT AVAIL
IS2	IS	1.30E-02	CONTAINMENT ISOLATION - LOSS OF A1 OR A2
IS3	IS	1.10E-01	CONTAINMENT ISOLATION - LOSS OF A1 & A2
LA1	LA	1.40E-02	RHR DIV I - ALL SUPPORT AVAIL
LAF	LA	1.00E+00	RHR DIV I - LOSS OF SUPPORT
LB1	LB	1.40E-02	RHR DIV II - ALL SUPPORT AVAIL & LA GUAR FAIL
LB3	LB	1.00E-02	RHR DIV II - ALL SUPPORT AVAIL & LA SUCCESS
LBA	LB	3.40E-02	RHR DIV II - ALL SUPPORT AVAIL & LA FAILED
LBF	LB	1.00E+00	RHR DIV II - LOSS OF SUPPORT
N23	N2	2.00E-02	NITROGEN (COMP2=S*COMP3=F)
OD1	OD	1.00E-02	OPERATORS EMERGENCY DEPRESSURIZE RPV
SD1	SD	1.00E+00	SHUTDOWN COOLING GIVEN NITROGEN FAILS

Table 3.2-1B
Master Frequency File (NUREG)

SF Name	Top Event	SF Value	Split Fraction Description
A12	A1	5.30E-02	DIV I AC POWER GIVEN LOSP
A24	A2	5.20E-02	DIV I AC POWER GIVEN LOSP & A1 SUCCESS
A28	A2	6.50E-02	DIV I AC POWER GIVEN LOSP & A1 FAILURE
COMP11	COMP1	1.20E-06	SEISA, g Levels: .08 to .15
COMP12	COMP1	1.50E-04	SEISB, g Levels: .15 to .25
COMP13	COMP1	1.80E-03	SEISC, g Levels: .25 to .31
COMP14	COMP1	8.60E-03	SEISD, g Levels: .31 to .41
COMP15	COMP1	5.80E-02	SEISE, g Levels: .41 to .66
COMP16	COMP1	2.70E-01	SEISF, g Levels: .66 to 1.02
COMP21	COMP2	1.60E-03	SEISA, g Levels: .08 to .15
COMP22	COMP2	3.50E-02	SEISB, g Levels: .15 to .25
COMP23	COMP2	1.50E-01	SEISC, g Levels: .25 to .31
COMP24	COMP2	3.00E-01	SEISD, g Levels: .31 to .41
COMP25	COMP2	5.90E-01	SEISE, g Levels: .41 to .66
COMP26	COMP2	8.90E-01	SEISF, g Levels: .66 to 1.02
COMP31	COMP3	1.70E-02	SEISA, g Levels: .08 to .15
COMP32	COMP3	1.70E-01	SEISB, g Levels: .15 to .25
COMP33	COMP3	4.40E-01	SEISC, g Levels: .25 to .31
COMP34	COMP3	6.40E-01	SEISD, g Levels: .31 to .41
COMP35	COMP3	8.60E-01	SEISE, g Levels: .41 to .66
COMP36	COMP3	9.80E-01	SEISF, g Levels: .66 to 1.02
HS1	HS	2.80E-02	HPCS - ALL SUPPORT AVAIL
HS2	HS	1.40E-01	HPCS - LOSP
IC1	IC	1.60E-01	RCIC
IS1	IS	5.30E-03	CONTAINMENT ISOLATION - ALL SUPPORT AVAIL
IS2	IS	1.30E-02	CONTAINMENT ISOLATION - LOSS OF A1 OR A2
IS3	IS	1.10E-01	CONTAINMENT ISOLATION - LOSS OF A1 & A2
LA1	LA	1.40E-02	RHR DIV I - ALL SUPPORT AVAIL
LAF	LA	1.00E+00	RHR DIV I - LOSS OF SUPPORT
LB1	LB	1.40E-02	RHR DIV II - ALL SUPPORT AVAIL & LA GUAR FAIL
LB3	LB	1.00E-02	RHR DIV II - ALL SUPPORT AVAIL & LA SUCCESS
LBA	LB	3.40E-02	RHR DIV II - ALL SUPPORT AVAIL & LA FAILED
LBF	LB	1.00E+00	RHR DIV II - LOSS OF SUPPORT
N23	N2	2.00E-02	NITROGEN (COMP2=S*COMP3=F)
OD1	OD	1.00E-02	OPERATORS EMERGENCY DEPRESSURIZE RPV
SD1	SD	1.00E+00	SHUTDOWN COOLING GIVEN NITROGEN FAILS

Table 3.2-2
Core Damage Sequences Greater Than 1E-9/yr (EPRI)

Rank	Initator	Frequency	Failed Split Fractions
1	SEIS4	5.71E-08	/COMP14
2	SEIS5	5.10E-08	/COMP15
3	SEIS6	4.18E-08	/COMP16
4	SEIS4	1.82E-08	/COMP24*COMP34*HS2*IC1*SD1
5	SEIS3	1.62E-08	/COMP33*A12*A28
6	SEIS4	7.96E-09	/COMP34*A12*A28
7	SEIS5	6.39E-09	/COMP25*COMP35*HS2*IC1*SD1
8	SEIS1	4.23E-09	/COMP11
9	SEIS3	4.04E-09	/COMP23*HS1*IC1*SD1
10	SEIS3	3.70E-09	/COMP13
11	SEIS3	3.06E-09	/COMP33*A24*LA1*LBF
12	SEIS4	3.05E-09	/COMP24*HS1*IC1*SD1
13	SEIS4	2.80E-09	/COMP24*COMP34*A12*A28
14	SEIS3	2.20E-09	/COMP33*A12*LAF*LB3
15	SEIS3	2.10E-09	/COMP33*N23*HS2*IC1*SD1
16	SEIS3	2.00E-09	/COMP33*A12*A28*IS3
17	SEIS3	1.90E-09	/COMP33*LA1*LBA
18	SEIS6	1.80E-09	/COMP26*COMP36*HS2*IC1*SD1
19	SEIS3	1.60E-09	/COMP23*COMP33*HS2*IC1*SD1
20	SEIS4	1.51E-09	/COMP34*A24*LA1*LBF
21	SEIS2	1.23E-09	/COMP32*A12*A28
22	SEIS4	1.08E-09	/COMP34*A12*LAF*LB3
23	SEIS3	1.03E-09	/COMP33*HS2*IC1*OD1
24	SEIS4	1.03E-09	/COMP34*N23*HS2*IC1*SD1
25	SEIS4	1.00E-09	/COMP24*COMP34*A12*HS2*IC1*SD1

Table 3.2-3
Top Event Importance Sorted by Fussel-Vesely (EPRI)

Top Event	Prob	Guar. Event	Tot. Fraction	Fussel-Vesely	Achieve Worth	Reduct. Worth	Frequency
COMP1	6.25E-01	0.00E+00	6.25E-01	6.15E-01	5.92E+04	3.85E-01	1.58E-07
COMP3	3.42E-01	0.00E+00	3.42E-01	3.15E-01	3.40E+02	6.85E-01	8.64E-08
IC	1.77E-01	0.00E+00	1.77E-01	1.75E-01	1.92E+00	8.25E-01	4.46E-08
HS	1.84E-01	0.00E+00	1.84E-01	1.75E-01	2.91E+00	8.25E-01	4.65E-08
SD	0.00E+00	1.67E-01	1.67E-01	1.67E-01	1.00E+00	8.33E-01	4.21E-08
A2	1.68E-01	0.00E+00	1.68E-01	1.58E-01	3.37E+00	8.42E-01	4.23E-08
COMP2	1.84E-01	0.00E+00	1.84E-01	1.53E-01	2.95E+02	8.47E-01	4.66E-08
A1	1.60E-01	0.00E+00	1.60E-01	1.50E-01	3.68E+00	8.50E-01	4.04E-08
LA	4.63E-02	1.92E-02	6.54E-02	4.63E-02	4.26E+00	9.54E-01	1.65E-08
LB	3.88E-02	2.67E-02	6.54E-02	3.88E-02	3.45E+00	9.61E-01	1.65E-08
N2	1.59E-02	0.00E+00	1.59E-02	1.47E-02	1.72E+00	9.85E-01	4.01E-09
OD	8.96E-03	0.00E+00	8.96E-03	7.26E-03	1.72E+00	9.93E-01	2.26E-09
IS	1.48E-02	0.00E+00	1.48E-02	0.00E+00	1.00E+00	1.00E+00	3.74E-09

3.3 USI A-45, GI-131, and Other Seismic Safety Issues

USI A-45 Shutdown Decay Heat Removal Requirements
No weaknesses were identified in the SMA analysis in Section 3.1 with regard to decay heat removal (USI A-45) or any other seismic issues. A plant HCLPF of 0.5g can be associated with the RHR system and its support systems. The seismic PRA in Section 3.2 further puts this risk into perspective by showing seismic risk is low at NMP2. As modeled, loss of heat removal is less than 2.2E-7/yr using the NUREG hazard. The SPRA assumes that core damage occurs at the plant HCLPF of 0.5g and assigns this to early loss of injection versus loss of heat removal. This contribution to core damage is 9E-7/yr using the NUREG hazard. However, the RHR system is judged to have seismic capabilities as good as other systems, including support systems, that would lead to loss of injection. Thus, a more detailed fragility analysis would likely show that loss of heat removal risk is lower than the 9E-7/yr value.

USI A-40 Seismic Design Criteria and A-46 Verification of Seismic Adequacy of Equipment
These issues are not applicable to NMP2 since the plant was designed to NRC criteria and methods that contain resolution of these issues (these issues apply to pre Standard Review Plan plants). Also, the seismic analysis in Sections 3.1 and 3.2 further show that these are not issues at NMP2.

USI A-17 Systems Interactions in Nuclear Power Plants
Unanalyzed spatial interactions as well as interaction due to relay chatter were considered in the seismic analysis (Section 3.1).

Control system interactions that can propagate via the electrical and control systems due to a seismic event were considered. The process involved both a deductive and inductive evaluation. Control system devices, relays, sensors, thermal overloads, electrical contactors and breakers were considered.

The deductive portion consisted of identifying electrical and control system devices whose failure or change in state can cause failure of a success path component or system. Once identified, a further evaluation was performed to determine if there were mechanisms such as operation of a master relay, that could cause the state change. This process was repeated for all systems and components in the seismic success path. The results of this analysis was captured in a relay impact diagram discussed in Section 3.1.2. For example, consider a seismic success path component such as a motor starter that stops by actuation of a relay (R1), that is actuated by an interposing relay (R2), which in turn is actuated by a master relay (R3). In addition, R3 and R2 also actuate other relays and each of these relays have similar and/or different dependencies on an upstream relay. There are several different impact combinations such as, R3 actuates but R2 does not (it failed) or R2 & R3 actuated but R1 did not or R2 and R1 actuated but R3 did not. This was developed to show how the component in the seismic success path can be impacted as well as to show impacts on other components that are not in the seismic success path. In addition, it showed how combinations can be generated and evaluated. An individual evaluation was terminated when it was obvious that systems in the seismic success path were not being impacted either directly or indirectly.

The inductive portion evaluates the impact of the various combinations and configurations developed above. When an adverse condition was identified, the initiators were identified as requiring a seismic fragility evaluation.

Also, systems interactions were considered during the walkdown as documented in the SEWS[10]. Section 3.1.2.1.5 provides additional documentation on the evaluation of potential spatial systems interactions considered in the seismic analysis. Section 4.8 provides an evaluation of potential seismic induced fires, fire water system actuation and failures.

Eastern U.S. Seismicity Issue

This issue is resolved by this IPEEE per Generic Letter 88-20, Supplement 4. The work carried out by NRC, LLNL and EPRI are considered in the seismic PRA and was taken into account in determining the review level earthquake.

4 Internal Fire Analysis

The analysis of internal fire risk utilizes both the EPRI FIVE[25] methodology and fire PRA methods[26]. The FIVE methodology recognizes that the IPE should be used both to screen fire areas and provide the basis for more detailed analysis of vulnerabilities. In a fire PRA, areas would have to be screened based on quantitative insights from the PRA that includes the potential for plant trip initiating events and the impact on systems modeled in the PRA (IPE). Thus, the FIVE methodology is not significantly different from a fire PRA except that FIVE is slightly more prescriptive with regard to analysis steps and procedures. Also, it was recognized that the combined unavailability of all four safe shutdown trains at NMP2 was not sufficient to screen out areas without knowledge of other shutdown paths. Thus, all areas were screened and evaluated utilizing the IPE[1] which considered the potential for plant initiators and the impact on equipment and systems modeled in the IPE.

The overall methodology is similar to that used in risk analysis of other hazards, such as seismic or tornados, where the hazard becomes the initiating event for the risk model. Specifically, a fire PRA is typically developed by defining plant areas (i.e., those defined in the Appendix R safe shutdown analysis), identifying the location of equipment modeled in the internal events PRA (IPE) within these areas, and assessing the impact on plant operation caused by a fire in each area (i.e., potential initiating event and damage to systems modeled in the IPE). The frequency of core damage can be quantified using the same internal events PRA model. Fire initiating events are defined by location, impact of the fire initiator is modeled by assuming failure of components and systems affected by the fire event, and the IPE model includes the unavailability of components and systems not affected by the fire initiator. Thus, the IPE can be used to quantify the frequency of core damage and release damage states given that the fire analysis has defined the frequency and impact of fires by location properly.

The following summarizes the approach and methods used in this analysis:

1. Utilizing the FIVE methodology, compartment boundaries were evaluated and fire ignition frequencies were developed for each compartment[27]. Also, Appendix R exemptions and deviations were assessed to assure that their potential impacts on this IPEEE analysis were understood. A plant walkdown was included as part of this analysis.

2. A computerized spatial database[28] was developed such that all plant cables and components in a fire zone could be identified. This was necessary to accurately identify the impacts of a fire on systems and components in each area.

3. Location dependencies were identified for the offsite power supplies, main feedwater, main condenser, and their support systems[29]. This provides additional success paths and results in improved plant reliability for screening and evaluating areas. The IPE was used to identify the systems and dependencies necessary to support these key

functions. Then, cable block diagrams were developed, identifying critical cables. With these cables and their impact on the IPE identified, the spatial database was utilized to determine the fire zones where these critical cables were located.

4. The spatial database, Appendix R database[6], and location dependencies for non Appendix R equipment were all used to identify component and system impacts on the IPE due to a fire in each area. Initial screening assumes the fire fails all cables and components in the area. Fire impact includes consideration of initiating events (plant trip or immediate shutdown) and unavailability of systems modeled in the IPE.

5. Based on the impact and frequency of a fire in the area, a screening process[29] was used to determine whether a fire in the area represents an insignificant contribution to core damage frequency or whether detailed analysis should be performed. The IPE is used to support both quantitative and qualitative screening judgments. This task was equivalent to accomplishing the FIVE qualitative and conservative quantitative screening.

6. Those areas that did not screen out during the initial screening analysis (item 5 above) were evaluated in greater detail[30] to establish realistic scenario frequencies or to screen the areas out. This analysis considered each unscreened area in greater detail including proximity of important cables, fire severity, fire causes and suppression. At this point in the analysis, fire modeling aspects of FIVE (i.e., identifying targets & sources, combustible loading, damage thresholds and suppression) were used as necessary to support the evaluation[31]. Plant walkdowns were an important part of the detailed analysis strategy for screening areas.

7. Containment performance, fire scoping issues[32], and USIs were assessed with regard to impact on public safety[27, 29, 30].

This initial screening analysis is described in Section 4.6.1 and the results of the initial screening analysis (item 5) is provided in Table 4.0-1. Those compartments with a screening core damage frequency greater than 1E-6/yr are evaluated further in Section 4.6.2 (item 6) and the results are summarized in Table 4.0-2. With the exception of the control room, all locations were screened out below the 1E-6/yr screening criteria in FIVE. Also, the analysis provides confidence that core damage frequency would be <1E-7/yr for the typical location in the plant with the exception of the control room. The frequency of core damage due to fires in the control room was estimated to be on the order of 1E-6/yr as discussed in Section 4.6.2.

Table 4.0-3 provides a comparison of the FIVE methodology steps versus the evaluation conducted at NMP2.

TABLE 4.0-1 INITIAL SCREENING ANALYSIS SUMMARY & NOTES (3)

Area	Zone	Description	Fire Freq	App R	Initiator	Screening Summary	OG	A1/2	RW	TW	AS	CN	FW	HS	IC	LA	LB	LC	LS	SV	CV
1	201SW	North Aux Bay-LPCS pump	4.8E-03	I	yes (1)	CDF <1E-8													X		
1	202SW	North Aux Bay-RHR A pump	3.1E-03	I	yes (1)	CDF <1E-7										X					
1	203SW	North Aux Bay-RHR HE 1A	2.4E-03	I	yes (1)	CDF <1E-7										X					
1	211SW	North Aux Bay-RHR & CCP HE	2.4E-03	I	yes (1)	CDF <1E-7										X			X		
1	221SW	North Aux Bay-SWP to CCP	3.1E-04	I	RWX	CDF = 2.9E-7			X			X			X	X			X	I	M1
1	231SW	North Aux Bay-MCC area	9.9E-04	I	RWX	CDF = 9.2E-7			X			X	X		X	X			X	I	M1
2	204SW	RCIC pump room	4.2E-03	I	no	RCIC unavail insignificant									X						
3	206SW	South Aux Bay-RHR B HE	2.4E-03	II	yes (1)	CDF <1E-7											X				
3	207SW	South Aux Bay-RHR B pump	4.2E-03	II	yes (1)	CDF <1E-7											X				
3	208SW	South Aux Bay-LPCI C pump	3.6E-03	II	yes (1)	CDF <1E-8												X			
3	214SW	South Aux Bay-RHR HE 1B	3.4E-04	II	yes (1)	CDF <1E-7											X	X			
3	224SW	South Aux Bay-South access	2.4E-03	II	RWX	CDF <1E-7			X			X			X		X	X			
3	239SW	South Aux Bay-MCC area	9.9E-04	II	RWX	CDF = 3.3E-7			X			X			X		X	X			M2
4	205NZ	HPCS pump room	4.7E-03	III	no	HPCS unavail insignificant								X							
5	234NZ	Drywell	0.0E+00	(2)	(2)	(2)															
8	301NW	140 degree tunnel	1.5E-04	I	A1X	CDF=3E-7		A1				X	X								Air
8	302NW	35 degree tunnel	1.4E-05	I	A1X	CDF<1E-7		A1	X			X	X								Air
10	303NW	315 deg tunnel	1.2E-05	N	RWX	CDF<1E-7			X			X	X								
16	306.1NW	Div I/II cable area-general area	1.6E-04	I	RWX	CDF=3E-7			X			X	X								Air
16	306.2NW	Document storage room	5.3E-04	N	no	no initiator or impact															
16	312NZ	Div I/II cable area-general area	2.2E-04	I	MSIV	CDF<1E-7						X			X						
16	321NW	Div I riser area	1.5E-04	I	A1X	CDF=3E-7	KAR	A1	X	X		X	X		X						Air
16	332NW	Div I cable chase West	1.5E-04	I	LOSP	CDF=1E-5	OG	A1	X	X	X	X	X		X						Air
16	352NW	Div I cable chase West	1.6E-04	I	LOSP	CDF=1.1E-5	OG	A1	X	X	X	X	X		X						Air
16	362.2NZ	Pipe tunnel (FA55 362NZ)	2.3E-04	I	RWX	<1E-7															
16	371NW	Div I cable chase West	1.5E-04	I	LOSP	CDF=1E-5	OG	A1	X	X	X	X	X		X						Air
17	305NW	Div I riser area	1.3E-05	I	RWX	CDF<1E-7			X	X		X	X		X						Air
17	322NW	Div I cable routing area	1.5E-04	I	A1X	CDF=3E-7	KAR	A1				X	X		X						Air
17	325NW	Div I cable routing area	1.3E-05	I	A1X	CDF<1E-7	KAR	A1							X						
17	333XL	Div I standby switchgear room	9.9E-04	I	A1X	CDF=2E-6	KAR	A1							X						DW
17	334NZ	Div I battery room	5.1E-04	I	D1X	CDF<1E-7 (D1 - Div I DC)									X						
17	343NZ	Remote shutdown room A West	1.5E-04	I	A1X	CDF=3E-7		A1							X						
17	NONEXX	Fire Protection Valve Room	2.3E-04	I	A1X	CDF=4.6E-7		A1													
18	304NW	230 degree tunnel	1.5E-04	II	A2X	CDF = 3E-6		A2				X		X							X
18	309NW	Cable chase East	1.3E-05	II	A2X	CDF = 2.6E-7		A2	X			X	X	X							
18	324NW	Div II riser area	1.5E-04	II	A2X	CDF = 3E-6	KBR	A2	X			X	X	X							X

TABLE 4.0-1 INITIAL SCREENING ANALYSIS SUMMARY & NOTES (3)																					
Area	Zone	Description	Fire Freq	App R	Initiator	Screening Summary	OG	A1/2	RW	TW	AS	CN	FW	HS	IC	LA	LB	LC	LS	SV	CV
18	337NW	Div 2/3 cable chase East	1.5E-04	II	A2X	CDF = 3E-6	KBR	A2	X		IB	X	X	X							X
18	359NW	Div 2/3 cable chase East	1.5E-04	II	A2X	CDF = 3E-6	KBR	A2	X		IB	X	X	X							X
18	377NW	Div 2/3 cable chase East	1.5E-04	II	A2X	CDF = 3E-6	KBR	A2	X			X	X	X							X
19	323NW	Div II cable routing area	1.5E-04	II	A2X	CDF = 3E-6	KBR	A2				X		X							X
19	326NW	Div II cable routing area	1.3E-05	II	A2X	CDF = 2.6E-7	KBR	A2						X							
19	335NZ	Div II battery room	5.1E-04	II	D2X	CDF<1E-7 (D2 - Div II DC)															
19	336XL	Div II standby switchgear room	9.7E-04	II	A2X	CDF = 1.9E-5	KBR	A2	X		IB			X							
19	338NZ	Remote shutdown room B East	1.5E-04	II	A2X	CDF = 3E-6		A2													
21	327NW	HPCS cable routing area	1.5E-04	III	no	HPCS unavail insignificant								X							
21	342XL	HPCS Switchgear	9.8E-04	III	no	HPCS unavail insignificant								X							
22	340NZ	Div I chiller	3.8E-03	I	no	No initiator or impact on IPE															
23	341NZ	Div II chiller	3.8E-03	II	no	No initiator or impact on IPE															
24	356NZ	PGCC relay (353,354,362SG)	2.3E-04	I & II	yes	CDF=2.3e-4		X													
24	357XL	PGCC computer room (358XG)	1.5E-04	I & II	yes	CDF=1.5e-4		X													
25	360NZ	Div I CR HVAC room	2.8E-03	I	no	No initiator or impact on IPE															
26	373.1NZ	Control Room (372-376)	9.9E-03	I & II	yes	CDF=9.9e-3		X													
26	373.2NZ	Shift supervisors office	2.3E-04	I & II	yes	CDF=2.3-4		X													
26	373.3NZ	Training room	2.3E-04	I & II	yes	CDF=2.3e-4		X													
27	378NZ	Div II CR HVAC room	2.5E-03	II	MSIV	CDF<1E-7						X									
28	401.1NZ	Div I diesel generator-CR	2.7E-03	I	no	EDG unavailability insignificant		EDG													
28	402.1SW	Div I diesel generator	2.9E-02	I	no	EDG unavailability insignificant		EDG													
29	401.2NZ	Div II diesel generator-CR	2.7E-03	II	no	EDG unavailability insignificant		EDG													
29	403.1SW	Div II diesel generator	2.9E-02	II	no	EDG unavailability insignificant		EDG													
30	401.3NZ	HPCS diesel control room	2.7E-03	III	no	EDG unavailability insignificant								EDG							
30	404.1SW	HPCS diesel generator	2.9E-02	III	no	EDG unavailability insignificant								EDG							
34	0NA	North reactor building	3.9E-02(4)	I		See Zones below															
34	212SW	North reactor building El 175	1E-2(4)	I	RWX	CDF = 8E-6			X				X		X	X			X		Air
34	222SW	North reactor building El 215	1E-2(4)	I	RWX	CDF = 8E-6			X			X	X		X	X			X	I	Air
34	232SW	North reactor building El 240	1E-2(4)	I	RWX	CDF = 8E-6		EDG	X			X	X		X	X			X	I	Air
34	243SW	North reactor building El 261	1E-2(4)	I	RWX	CDF = 8E-6 (E1 - ECCS Div I)			2 of 3			X	X		X	X			X		Air
34	252SW	North reactor building El 289	1E-2(4)	I	RWX	CDF = 8E-6			X			X	2 of 3		X	X			X		Air
34	261SW	North reactor building El 306	1E-2(4)	I	no	No initiator or impact on IPE															Air
34	271SW	North reactor building El 328 NW	1E-2(4)	I	RWX	CDF<1E-6			X			X									MI
34	273SW	North reactor building El 328 NE	1E-2(4)	I	no	No initiator or impact on IPE															
34/35	281NZ	North reactor building El 353 and above	1E-2(4)	I	no	No initiator or impact on IPE															
34	242NW	Track bay (same as FA98)	5.3E-04(4)	N	no	No initiator or impact on IPE															

Area	Zone	Description	Fire Freq	App R	Initiator	Screening Summary	OG	A1/2	RW	TW	AS	CN	FW	HS	IC	LA	LB	LC	LS	SV	CV
35	0NA	South reactor building	3.8E-02(4)	II		See Zones below															
35	213SW	South reactor building El 175	1E-2(4)	II	RWX	CDF = 8E-6			X					X			X	X			
35	223SW	South reactor building El 215	1E-2(4)	II	RWX	CDF = 8E-6			X			X	X	X			X	X		II	X
35	238SW	South reactor building El 240	1E-2(4)	II	RWX	CDF = 8E-6			X			X	X	X			X	X		II	DW
35	245SW	South reactor building El 261	1E-2(4)	II	RWX	CDF = 8E-6 (E2 - Div II ECCS)			X			X	X	X			X	X		II	M2
35	255SW	South reactor building El 289	1E-2(4)	II	RWX	CDF = 8E-6			X					X			X	X			DW
35	262SW	South reactor building El 306	1E-2(4)	II	RWX	CDF<1E-6			X				2 of 3					X			M2
35	272SW	South reactor building El 328 SW	1E-2(4)	N	RWX	CDF<1E-6			X												
35	274SW	South reactor building El 328 SE	1E-2(4)	II	no	no initiator or impact on IPE															
38	311NZ	Computer battery room	5.1E-04	N	no	no initiator or impact on IPE															
39	307NZ	Div I West battery room	5.0E-04	N	no	no initiator or impact on IPE															
40	308NZ	Div II East battery room	5.0E-04	N	no	no initiator or impact on IPE															
42	708NW	Oil storage tank	3.8E-03	N	yes	CDF <1E-7						IF	2 of 3								
48	236NZ	Div I HVAC room	2.4E-03	I	no	no initiator or impact on IPE															
49	701NW	RR track bay	5.3E-04	N	no	no initiator or impact on IPE															
49	CHWTR	Chilled water STR	6.0E-03	N	no	no initiator or impact on IPE															
50	256NZ	Main steam tunnel	6.2E-04	I	yes	CDF <1E-8		EDG				X	X								
50	702NZ	Turbine building	3.6E-02	N	yes	CDF = 5.8E-7															
50	703NZ	Turbine building	8.3E-04	N	yes	CDF <1E-7						X									
50	704NZ	Turbine building	8.7E-04	N	yes	CDF <1E-7							1 of 3								
50	705NZ	Turbine building	8.7E-04	N	yes	CDF <1E-7							1 of 3								
50	706NZ	Turbine building	8.7E-04	N	yes	CDF <1E-7							1 of 3								
50	707SW	Turbine building	5.9E-04	N	yes	CDF <1E-8					IC	X									
50	709NZ	Turbine building	5.0E-03	N	yes	CDF <1E-7					X	X	X								
50	716SW	Turbine building (717, 718SW)	1.3E-02	N	yes	CDF = 2.1E-7				X	X	X	X								
50	721NZ	Turbine building	5.9E-04	N	yes	CDF <1E-8						X									
50	722NZ	Turbine building	7.9E-04	N	yes	CDF <1E-7															
50	723NZ	Turbine building	6.8E-04	N	yes	CDF <1E-7							1 of 3								
50	724NZ	Turbine building	6.8E-04	N	yes	CDF <1E-7							1 of 3								
50	725NZ	Turbine building	6.8E-04	N	yes	CDF <1E-7							1 of 3								
50	727SW	Turbine building (730, 731SW)	7.0E-03	N	yes	CDF = 1.1E-7					IA,IC	X	X								
50	728NZ	Turbine building	5.3E-04	N	yes	CDF <1E-8							X								
50	729NZ	Turbine building	5.3E-04	N	yes	CDF <1E-8															
50	751NZ	Turbine building	2.1E-03	N	yes	CDF <1E-7															
50	752.1NZ	Turbine building	1.1E-03	N	yes	CDF <1E-7						X									
50	752.2NZ	Turbine building	1.5E-03	N	yes	CDF <1E-7						X									

Table: TABLE 4.0-1 INITIAL SCREENING ANALYSIS SUMMARY & NOTES (3)

TABLE 4.0-1 INITIAL SCREENING ANALYSIS SUMMARY & NOTES (3)

Area	Zone	Description	Fire Freq	App R	Initiator	Screening Summary	OG	A1/2	RW	TW	AS	CN	FW	HS	IC	LA	LB	LC	LS	SV	CV
50	753NZ	Turbine building	2.1E-03	N	yes	CDF <1E-7															
50	754NZ	Turbine building	5.8E-04	N	yes	CDF <1E-8															
50	755NZ	Turbine building	1.5E-02	N	yes	CDF = 2.4E-7															
50	756NZ	Turbine building	5.8E-04	N	yes	CDF <1E-8															
50	762NZ	Turbine building	5.3E-04	N	yes	CDF <1E-8															
50	763NZ	Turbine building	2.1E-03	N	yes	CDF <1E-7															
50	764NZ	Turbine building	5.3E-04	N	yes	CDF <1E-8															
51	601XL	West normal switchgear	9.7E-04	N	LOSP	CDF = 1.1E-6 - blackout	OG		X	X	X	X	X								
52	602XL	East normal switchgear	1.1E-03	N	LOSP	CDF = 1.3E-6 - blackout	OG		X	X	X	X	X								
52	604NZ	East normal switchgear	9.6E-04	N	KBX	CDF <1E-7	KBR		X	X	X		1 of 3								
53	603NZ	Battery rooms	4.9E-04	N	LOSP	CDF = 5.8E-7 - blackout	OG			X	1A,1B	X	X								
55	237NZ	Div II HVAC room	2.4E-03	II	RWX	CDF <1E-7			X	X											
55	361NZ	Pipe tunnels	2.3E-04	II	RWX	CDF <1E-7			2 of 3	X		3 of 6	2 of 3								
55	362.1NZ	Pipe tunnels (FA16 362.2NZ)	2.3E-04	II	RWX	CDF <1E-7			2 of 3	X		3 of 6	2 of 3								
55	363NZ	Pipe tunnels El 244	2.3E-04	II	TWX	CDF <1E-7				X											
55	811NZ	Service water intake/disch area	2.3E-04	N	no	no initiator or impact on IPE															
55	902NW	Condensate storage tanks	2.7E-03	N	LOC	CDF <1E-7						X									
57	961NW	Asphalt tank and pumps	7.4E-04	N	no	no initiator or impact on IPE															
58	901NZ	LWS - Radwaste	7.5E-04	N	no	no initiator or impact on IPE															
58	904NZ	LWS - Radwaste	7.4E-04	N	no	no initiator or impact on IPE															
58	906NZ	LWS - Radwaste	7.7E-04	N	no	no initiator or impact on IPE															
58	911NW	LWS - Radwaste	7.9E-04	N	no	no initiator or impact on IPE															
58	941NW	LWS - Radwaste	7.6E-04	N	no	no initiator or impact on IPE															
59	908NZ	WSS - Radwaste	7.4E-04	N	no	no initiator or impact on IPE															
59	921SW	WSS - Radwaste	7.5E-04	N	no	no initiator or impact on IPE															
59	951NW	WSS - Radwaste	7.5E-04	N	no	no initiator or impact on IPE															
60	807NZ	Service water pump B	6.0E-03	II	SAX	CDF = 3.2E-6 (SB)						3 of 6									
60	808NZ	Auxiliary boiler room	3.0E-03	N	no	no initiator or impact on IPE															
61	806NZ	Service water pump A	6.0E-03	I	SAX	CDF = 3.2E-6 (SA)						3 of 6									
62	804NW	Diesel fire pump room	6.6E-03	N	no	no initiator or impact except fire pump															
63	805NZ	Electric fire pump room	6.7E-03	N	no	no initiator or impact except fire pump															
64	715NZ	Foam pump room	5.8E-03	N	no	no initiator or impact on IPE															
65	714NW	I&C shop	5.3E-04	N	no	no initiator or impact on IPE															
66	402.2SW	Div I diesel day tank	2.3E-04	I	no	EDG unavail insignificant		EDG													
67	403.2SW	Div II diesel day tank	2.3E-04	II	no	EDG unavail insignificant		EDG													
68	404.2SW	HPCS diesel day tank	2.3E-04	III	no	EDG unavail insignificant								EDG							

TABLE 4.0-1 INITIAL SCREENING ANALYSIS SUMMARY & NOTES (3)

Area	Zone	Description	Fire Freq	App R	Initiator	Screening Summary	OG	A1/2	RW	TW	AS	CN	FW	HS	IC	LA	LB	LC	LS	SV	CV
69	801NZ	Water treatment building	6.2E-03	N	no	no initiator or impact on IPE															
70	395XL	Radwaste switchgear room	9.8E-04	N	LOF	CDF <1E-7					IC	X	X								
70	903NZ	Decon area & RW CR	7.8E-04	N	no	no initiator or impact on IPE															
70	905NW	Decon area & RW CR	7.6E-04	N	no	no initiator or impact on IPE															
70	907NZ	Decon area & RW CR	7.5E-04	N	no	no initiator or impact on IPE															
71	803,802NZ	Intake area/Screenwell Bldg	6.6E-03	II	LOC	CDF <1E-7						X									
72	351.1NZ	Instrument shop El 288 CB	5.3E-04	I & III	A1X	CDF=5.8E-7 based on 380.1		A1		X				X							
72	351.2NZ	Corridor El 288 CB	5.3E-04	I & III	A1X	CDF=5.8E-7 based on 380.1		A1		X				X							
73	247NZ	Standby gas treatment-A	2.4E-03	N	no	no initiator or significant impact															X
74	248NZ	Standby gas treatment-B	2.4E-03	N	no	no initiator or significant impact															X
75	339NZ	HPCS battery room	5.0E-04	III	no	HPCS unavail insignificant								X							
76	380.1NZ	Operators lunch room El 306	2.3E-03	I & III	A1X	CDF=2.5E-6		A1						X							
76	380.2NZ	Corridor/toilet El 306	5.3E-04	I & III	A1X	CDF=5.8E-7 based on 380.1		A1						X							
77	621NZ	Penthouse	3.8E-03	N	LOC	CDF <1E-7															
78	612XL	West normal switchgear	9.8E-04	N	LOSP	CDF = 1.2E-6 - blackout	OG		2 of 3	X	X	X	X								
79	613XL	East normal switchgear	9.7E-04	N	LOSP	CDF = 1.1E-6 - blackout	OG		X	X	1A,1B	X	X								
80	246NW	South Aux service building	5.9E-04	N	RWX	CDF <1E-7			X												
80	611NW	Electrical bay	1.5E-04	N	RWX	CDF <1E-7			X	X	X	X	X								
80	761.2NZ	Clean access area El 288	5.9E-04	N	RWX	CDF <1E-7			2 of 3			X	1 of 3								
80	761.3NZ	Clean access area El 306	5.9E-04	N	RWX	CDF <1E-7			2 of 3			X	2 of 3								
81	253XL	600V switchgear room	9.6E-04	N	RWX	CDF <1E-7			X				2 of 3								
82	732NW	Lube oil storage room	4.0E-03	N	yes	CDF <1E-7							1 of 3								
83	726XL	Normal switchgear East	9.8E-04	N	yes	CDF <1E-7					IC	X	X								
84	740XL	Normal switchgear West	9.8E-04	N	yes	CDF <1E-7					IC	2 OF 6	X								
85	251NW	Standby gas treatment-HVAC	3.7E-03	N	no	no initiator or impact on IPE															
86	274SW	Resin storage area	2.3E-03	N	no	no initiator or impact on IPE															
86	770NW	Cafateria and corridor	5.3E-04	N	no	no initiator or impact on IPE															
87	255SW	Div I SFC pump room (or 87SW)	3.5E-03	I	no	no initiator or impact on IPE															
88	331NW	Corridor El 261 CB	7.7E-04	I & III	LOSP	5.30E-05	OG	A1	X	X	X	X	X	X							
90	761.1NZ	Stairway enclosure	5.3E-04	N	RWX	CDF <1E-7			2 of 3												

Table 4.0-1 Notes

1. N2-EOP-SC, Rev 4 requires the operator to immediately shut down the plant per OP-101C & D if more than 1 RB area temperature exceeds 135F. This is assumed to occur in the North and South Auxiliary Bays.

2. The primary containment was qualitatively screened out. With the exception of instrumentation and containment venting valves, most equipment required to respond to an initiator in the drywell are located outside the primary containment. There is separation among the instrumentation and venting valves, and the primary containment is normally inerted during operation.

3. The following summarizes the column headings (IPE systems) and the codes used to summarize impacts:

   OG - Offsite AC power in the IPE is represented by four event tree top events. OG represents the offsite grid (OG failure equates to a total loss of all offsite power), KA represents 115KV source A, KB represents 115KV source B, and KR represents crosstie capabilities between KA and KB to plant loads. The following explains the impact codes used in the table:

   KAR - failure of both KA and KR capabilities
   KBR - failure of both KB and KR capabilities
   OG - failure of all offsite AC power (KA, KB & KR failed)

   A1/2 - Division I and II emergency AC power was modeled as top events A1 and A2 in the IPE. For those systems where simplified cable block diagrams were developed or detailed evaluation of cables was performed, the evaluations of each component considered cables up to the emergency and normal switchgear rooms and control complex. However, in some cases where Appendix R indicated that emergency AC was in the fire zone or if the area was not evaluated in detail, it may have been assumed. The following explains the impact codes used in the table:

   EDG - only the emergency diesel for the applicable Division is affected.
   A1 - Div I emergency AC failure occurs or is assumed.
   A2 - Div II emergency AC failure occurs or is assumed.
   X - failure of both divisions can occur or is assumed.

   RW - Reactor building closed loop cooling (RBCLC) is modeled in the IPE as top event RW. The impacts are based on evaluation of the critical cables required for RBCLC components. The following explains the impact codes used in the table:

   1 of 3 - one of three pump trains are impacted
   2 of 3 - two of three pump trains are impacted
   X - system failure occurs

Table 4.0-1 Notes

TW - Turbine building closed loop cooling (TBCLC) is modeled in the IPE as top event TW. The impacts are based on evaluation of the critical cables required for TBCLC components. The following explains the impact codes used in the table:

1 of 3 - one of three pump trains are impacted
2 of 3 - two of three pump trains are impacted
X - system failure occurs

AS - Instrument air is modeled in the IPE as top event AS. The impacts are based on evaluation of the critical cables required for instrument air components. The following explains the impact codes used in the table:

1A - compressor 1A is impacted
1B - compressor 1B is impacted
1C - compressor 1C is impacted
X - system failure occurs

CN - The main condenser is modeled in the IPE as top event CN. The impacts are based on evaluation of the critical cables required for main condenser and support system components. The following explains the impact codes used in the table:

1 of 6 - one of six circ water pumps are impacted
2 of 6 - two of six circ water pumps are impacted
3 of 6 - three of six circ water pumps are impacted
X - system failure due to more than 3 circ water pumps impacted and/or MSIVs close and/or main condenser or its support systems fail

FW - The main feedwater system is modeled in the IPE as top event FW. The impacts are based on evaluation of the critical cables required for feedwater and condensate components. The following explains the impact codes used in the table:

1 of 3 - one of three pump trains are impacted
2 of 3 - two of three pump trains are impacted
X - system failure occurs

HS, IC, LA, LB, LC, and LS model HPCS, RCIC, RHR "A", RHR "B", and LPCS, respectively in the IPE. The impact is either system failure, "X", or no impact. The impacts were developed from Appendix R evaluations and/or evaluations of cables in a specific fire zone.

Table 4.0-1 Notes

SV - Safety relief valves opening to allow low pressure injection is modeled in the IPE as top event SV. In general, the cables for this system were not evaluated in detail, because Appendix R assured that at least one Div of ADS is available. With one Div available, the unavailability of SV is low and in combination with the fire frequency is not significant. Still, if failure of A1 or A2 is assumed in Appendix R Div I or Div II areas that were not evaluated in detail, this results in loss of 1/2 of SV in the IPE. Thus, the impact is included where A1 and A2 are failed. In cases where SV impact was found, "I" or "II" is shown as an impact to represent Div I and II, respectively.

CV - Containment venting is modeled in the IPE as top event CV. The impacts are based on evaluation of the critical cables required for containment venting components. The following explains the impact codes used in the table:

M1 - Div I MOVs in the standby gas treatment system (SGTS) are impacted. This has an insignificant impact on containment venting capability since Div II MOVs are available and the Div I MOVs can be locally opened or closed.
M2 - Div II MOVs in the SGTS system are impacted. This has an insignificant impact on containment venting capability since Div I MOVs are available and the Div II MOVs can be locally opened or closed.
DW - Drywell venting is impacted. This has an insignificant impact on containment venting since the preferred path from the suppression chamber is available.
Air - The outside air operated valves and/or the 20" AOV101 must be locally opened. There may be other impacts such as M1 or M2 and/or drywell venting may fail, however, suppression chamber venting is available if the outside AOV is opened locally as modeled in the IPE.
X - system failure

Div I and II DC power (D1 and D2), vital AC (UA and UB), ECCS actuation (E1 and E2), and service water (SA and SB) were treated similarly to SV. Loss of service water or DC at the main source was modeled as an initiating event as shown in the table. Where cable evaluations were performed on main line systems or the BOP systems, cable evaluations and impacts were conducted to the electrical power source and controls.

(4) Reactor building fire zones were evaluated with a screening frequency of 1E-2/yr.

TABLE 4.0-2 Detailed Analysis Summary Results			
Area	Zone	Description	Detailed Analysis Summary
26	373.1NZ	Control room (372-376)	Not screened out. CDF judged to be on the order of 1E-7 to 1E-6/yr. Based on PGCC design and FMEA of electrical cabinets, most important spatial locations identified and evaluated. Also, control room fire events evaluated and more realistic initiating event frequency developed versus the 9.9E-3/yr value used in the initial screening.
24	356NZ	PGCC relay room (353,354,362SG)	Screened out. Based on PGCC design and FMEA of electrical cabinets, this area was screened out. The control room envelopes risk.
26	373.2NZ	Shift supervisors office	Screened out. Subsequent to the initial screening analysis, it was determined that there was no important safety or nonsafety cables in the room. This was confirmed by walkdown and screened out.
26	373.3NZ	Training room	Screened out. Subsequent to the initial screening analysis, it was determined that there was no important safety or nonsafety cables in the room. This was confirmed by walkdown and screened out.
24	357XL	PGCC computer room (358XG)	Screened out. Subsequent to the initial screening analysis, it was determined that there was no important safety or nonsafety cables in the room. This was confirmed by walkdown and screened out.
88	331NW	Corridor El 261 CB	Screened out. A fire that impacts offsite power and the Div I diesel was found to be remote. Also, the portion of the corridor that contains offsite power, HPCS and balance of plant cables has automatic detection and suppression.
19	336XL	Div II standby switchgear room	Screened out. This area contains automatic detection and total flooding carbon dioxide for suppression. Diesel cables enter the bottom of the switchgear and normal AC power cables enter from the ceiling. FMEA of cabinets used to focus analysis on the cabinets with greatest impact.
16	352NW	Div I cable chase West	Screened out. FMEA of cabinets performed plus evaluation of cables in proximity of those cabinets with vents.
16	332NW	Div I cable chase West	Screened out. FMEA of cabinets performed plus evaluation of cables in proximity of those cabinets with vents.
16	371NW	Div I cable chase West	Screened out. FMEA of cabinets performed plus evaluation of cables in proximity of those cabinets with vents.

TABLE 4.0-2 Detailed Analysis Summary Results			
Area	Zone	Description	Detailed Analysis Summary
34	212SW	El 175	Screened out. Walkdown performed to identify most likely scenarios based on dominant fire sources, arrangements and recognizing that automatic tray water sprays provide protection for most trays.
34	222SW	El 215	Screened out. See 34 212SW above.
34	232SW	El 240	Screened out. See 34 212SW above.
34	243SW	El 261	Screened out. See 34 212SW above.
34	252SW	El 289	Screened out. See 34 212SW above.
35	213SW	El 175	Screened out. See 34 212SW above.
35	223SW	El 215	Screened out. See 34 212SW above.
35	238SW	El 240	Screened out. See 34 212SW above.
35	245SW	El 261	Screened out. See 34 212SW above.
35	255SW	El 289	Screened out. See 34 212SW above.
60	807NZ	Service water pump B	Screened out. Sufficient separation between pumps, MCC which is in an enclosed cabinet, and cables such that loss of all Divisional pumps unlikely.
61	806NZ	Service water pump A	Screened out. Sufficient separation between pumps, MCC which is in an enclosed cabinet, and cables such that loss of all Divisional pumps unlikely
18	304NW	230 degree tunnel	Screened out. FMEA of cabinets performed plus evaluation of cables in proximity of those cabinets with vents.
18	324NW	Div II riser area	Screened out. FMEA of cabinets performed plus evaluation of cables in proximity of those cabinets with vents.
18	337NW	Div 2/3 cable chase East	Screened out. FMEA of cabinets performed plus evaluation of cables in proximity of those cabinets with vents.
18	359NW	Div 2/3 cable chase East	Screened out. FMEA of cabinets performed plus evaluation of cables in proximity of those cabinets with vents.
18	377NW	Div 2/3 cable chase East	Screened out. FMEA of cabinets performed plus evaluation of cables in proximity of those cabinets with vents.

TABLE 4.0-2 Detailed Analysis Summary Results			
Area	Zone	Description	Detailed Analysis Summary
19	323NW	Div II cable routing area	Screened out. FMEA of cabinets performed plus evaluation of cables in proximity of those cabinets with vents.
19	338NZ	Remote shutdown room B East	Screened out. More detailed evaluation of impacts determined that AC power was not impacted.
76	380.1NZ	Operators lunch room El 306	Screened out. Subsequent to the initial screening analysis, it was determined that only Div III HPCS was potentially impacted. This was confirmed by walkdown and screened out.
17	333XL	Div I standby switchgear room	Screened out. This area contains automatic detection and total flooding carbon dioxide for suppression. Diesel cables enter the bottom of the switchgear and normal AC power cables enter from the ceiling. FMEA of cabinets used to focus analysis on the cabinets with greatest impact.
52	602XL	East normal switchgear	Screened out. This area contains automatic detection and total flooding carbon dioxide for suppression. The total loss of offsite power as assumed in the initial screening was found to be unlikely based on a more careful review of cabinets and cable locations.
78	612XL	West normal switchgear	Screened out. This area contains automatic detection and total flooding carbon dioxide for suppression. The total loss of offsite power as assumed in the initial screening was found to be unlikely based on a more careful review of cabinets and cable locations.
51	601XL	West normal switchgear	Screened out. This area contains automatic detection and total flooding carbon dioxide for suppression. The total loss of offsite power as assumed in the initial screening was found to be unlikely based on a more careful review of cabinets and cable locations.
79	613XL	East normal switchgear	Screened out. This area contains automatic detection and total flooding carbon dioxide for suppression. The total loss of offsite power as assumed in the initial screening was found to be unlikely based on a more careful review of cabinets and cable locations.

Table 4.0-3 Summary Comparison of FIVE Methodology Steps Versus NMP2 Evaluation		
FIVE METHODOLOGY		EVALUATION METHODS & RESULTS
Phase 1 Fire Area Sceen (Qualitative Analysis)		
Step 1	Identify Plant Safe Shutdown Systems	Completed per FIVE (Reference 27)
Step 2	Identify Fire Areas and Compartments	Completed per FIVE (Reference 27)
Step 3	Identify Safe Shutdown Equipment in Each Compartment	Completed per FIVE (Reference 27)
Step 4	Perform Fire Area vs. Safe Shutdown System Screen	Completed per FIVE (Reference 27) including Revision 1 to FIVE isuued 9/29/93. Very few areas screened. Non Appendix R cable database not used or developed (a shutdown demand had to be assumed).
Step 5	Perform Fire Area vs. Safe Shutdown Function Evaluation	Completed per FIVE (Reference 27) except see step 4 above.
Step 6	Peform Fire Compartment Interaction Analysis	Completed per FIVE (Reference 27)
Phase II Critical Fire Compartment Screen (Quantitative Analysis)		
Step 1	Ignition Source Frequency	Completed per FIVE (Reference 27)
Step 2	Redundant/Alternate Shutdown Path Unavailability	Completed per FIVE (Reference 27). Very few areas screened. Appendix R safe shutdown reliability not high enough to support screening especially when assuming loss of offsite power. Fire PRA initiated within FIVE framework (References 28 and 29). IPE used to perform area screening of all areas regardless of whether they were screened in the above steps. To do this, non Appendix R critical cables were identifed with impacts on the IPE, the fire areas containing these cables and impacts were identified, and the IPE used to quantitatively screen. Those areas that did not screen this inital screening were evaluated in detail as summarized below in Step 3.
Step 3	Fire Hazards Analysis and Combustible Material Evaluation	Detailed fire PRA analysis completed within FIVE Framework (References 30 and 31). Considered sources, targets, automatic suppression and used walkdowns within a quantitative framework. Generic fire models and limited specific fire analysis performed per FIVE to support analysis and judgments.

Table 4.0-3 Summary Comparison of FIVE Methodology Steps Versus NMP2 Evaluation		
FIVE METHODOLOGY		EVALUATION METHODS & RESULTS
Step 4	Evaluate Potential Fire Vulnerabilities	Completed per FIVE (Reference 30 and this report). Control room screen is marginal and improved procedure & training being evaluated as possible cost beneficial improvement.
Step 5	Evaluate Potential Impact on Containment Heat Removal and Isolation	Completed per FIVE (Reference 30 and this report). Containment heat removal was included in the PRA approach used. Containment performance, including isolation, interfacing LOCA and other Level 2 PRA considerations were evaluated.
Phase III Plant Walkdown/Verification and Documentation		
Walkdown/Verification		Performed per FIVE (Reference 27) and supplemented as needed to support detailed PRA analysis (References 30 and 31).
Documentation		This report contains Tier 1 doumentation per NUREG-1407 and generally includes the recommendations in FIVE. Tier 2 documentation is contained in References 27 through 31 and generally includes the recommendations in FIVE.

4.1 Fire Hazard Analysis

Quantification of the ignition sources[27] in the plant and the cumulative fire ignition frequency based on those hazards and the EPRI fire incident database is discussed in the FIVE[25] methodology. Section 4.1.1 discusses how the FIVE mandated plant location designation assignments were made. Section 4.1.2 identifies how the information in FIVE on location specific ignition sources was applied at NMP2. Section 4.1.3 addresses the application of the FIVE methodology for plantwide ignition sources at NMP2.

The total fire ignition frequency developed from the analysis in this section can be seen in Table 4.0-1 for each compartment. These frequencies were used in the initial screening analysis described in Section 4.6.1. Table 4.1-1 summarizes the contributing ignition sources for each compartment developed from this analysis. These individual sources were considered in the detailed analysis (Section 4.6.2) of compartments when they could not be screened out using other methods.

The following summarizes how each ignition source frequency in Table 4.1-1 is calculated and the following sections describe the data base development further.

<u>Location Specific Sources</u>
The "Bldg" column in Table 4.1-1 identifies the plant location in FIVE Table 1.2 in which the compartment was assigned. The "Source" column in Table 4.1-1 identifies the fire ignition/fuel source in FIVE Table 1.2. With this information the fire frequency in FIVE Table 1.2 can be obtained and multiplied by the quantity of sources ("Qty" column in Table 4.1-1) and divided by the total number of locations ("LT" column in Table 4.1-1). The result is shown in Table 4.1-1 column "Freq". The following provides an example calculation for the electrical cabinet in FA01 201SW:

5.0E-2 (BWR RB Elec Cab)*1/24 = 2.08E-3

Where the annual frequency of fires from BWR reactor building (RB) electrical cabinets (Elec Cab) in FIVE Table 1.2 is 5.0E-2. The remaining data is shown in Table 4.1-1.

For some locations, the following overall weighting factor, WF_L, must be included in the above calculation (multiplied times the result):

Plant Location	Number of Rooms	WF_L
Switchgear room	16	0.063
Battery room	7	0.143
Cable spreading room	24	0.042
Radwaste areas	12	0.083

Development of these weighting factors is discussed in section 4.1.1.

Plant Wide Sources

Again, in order to calculate the "Freq" column in Table 4.1-1, the fire frequency in FIVE Table 1.2 is required for each plant wide source. In addition, the total quantity of each source within the plant is needed as summarized in the table below. The following provides an example calculation for transients in FA01 201SW:

1.3E-3 (Transients)*5/157 = 4.14E-5

Where the annual frequency of Transient fires in FIVE Table 1.2 is 1.3E-3. The remaining data is shown in the table below and in Table 4.1-1.

Plant Wide Source	Total Quantity in Plant
Transients	157
Welding/Ordinary	157
Welding/Cables	85
Ventilation/Fans	231
JB/Splices	17,280,000 ($X10^3$ BTU)
Elevator Motors	4
Air Compressors	24
MG Sets	4
H2 Recombiners	3
Transformers	167
Dryers	5

The detailed analysis of the control room, described in Section 4.6.2, required an evaluation of the actual fire events in the database[25]. This was necessary to realistically estimate core damage frequency due to fires in the control room. This investigation also suggests that many of the events in the database may not be severe enough to cause the damage typically assumed in the analysis. For these reasons, the frequencies developed in this section, including weighting factors, are considered to be reasonable to conservative and no effort was made to identify uncertainties in the above methodology.

4.1.1 Assignment of Plant Location Designations

Table 1.1 of FIVE Attachment 10.3 identifies the plant locations which EPRI determined represented all plant areas (with respect to the available fire incident data). These locations are summarized below:

- Auxiliary building (PWR)
- Reactor building (BWR)
- Diesel generator room
- Switchgear room
- Battery room
- Control room
- Cable spreading room
- Intake structure
- Turbine building
- Radwaste building
- Transformer yard
- Plant-wide components

The first two items listed are mutually exclusive for BWR/PWR plants and the last item is not a plant location but gives the overall weighting factor, WF_L, for components found throughout the plant - see section 4.1.3.

All of the fire areas or fire compartments identified while analyzing NMP2 had to be assigned to one of the above 10 categories (auxiliary building and plant-wide component categories are excluded) even though in the case of non-industrial spaces there is no obvious correlation. For example, office spaces do not seem to correspond well with the hazards normally associated with either the turbine building or reactor building, the only available plant location choices. Office and other non-industrial spaces outside the turbine building (except for spaces in the radwaste building which has its own plant location) were assigned to the reactor building plant location. This assignment was based on the fact that the ignition frequency for electrical cabinets (the presumed hazard in these areas) is higher for reactor building locations.

The electrical cable tunnels, cable routing areas and cable chases in the control building were assigned as cable spread rooms as the most appropriate designation among the 10 choices. Cable areas in the North and South auxiliary bays were identified as reactor building locations rather than as cable spread rooms as the frequency for electrical cabinet fires was higher for the reactor building. Pipe tunnels were included as part of the intake structure plant location designation as this was the best match for the hazards associated with the pipe tunnels. HVAC rooms in the control building were included as reactor building locations, again because this was the most conservative fire frequency.

Initial assignments of plant locations were occasionally changed based on the plant walkdown as the presence of switchgear and/or MCCs made the area more like a switchgear room than a cable spread room. The final location assignment is shown in Table 4.1-1, column "Bldg".

The overall weighting factor, WF_L, was assigned for each plant location based on the instructions given in the second column of FIVE Reference Table 1.1. For the plant locations where the number of compartments affect the overall weighting factor, the number of rooms/compartments is as follows:

Plant Location	Number of Rooms	WF_L
Switchgear room	16	0.063
Battery room	7	0.143
Cable spreading room	24	0.042
Radwaste areas	12	0.083

It should be noted that there are some decisions made with respect to the weighting factor which are not obvious from looking at the database tables. These are: 1) the DG oil day tank rooms; and, 2) the two spaces inside the plant control room; were assigned as diesel generator and control room plant locations, respectively. However, the weighting factor for these two plant locations was not revised to reflect six DG areas or three control room areas, as this would distort the fire frequency information taken from the EPRI database.

4.1.2 Location Specific Ignition Sources

Table 1.2 of FIVE Attachment 10.3 lists the fire ignition and/or fuel source associated with the 10 plant locations. In addition, this table lists the methodology for determining the weighting factors associated with each hazard and the baseline fire frequency based on the EPRI fire reporting database (and other sources). The following describes how the information for each ignition/fuel source was applied/determined at NMP2. The results are summarized in Table 4.1-1.

<u>Electrical Cabinets</u>
Electrical cabinets are the most common ignition source in FIVE Table 1.2, being associated with 7 of the 10 plant locations (the exceptions being the radwaste building, battery rooms and transformer yard). For five of the seven plant locations with electrical cabinets as a hazard there is no associated weighting factor, i.e., the ignition frequency is equal in all areas to the frequency found in the data base. (This implies that the distribution of electrical cabinets in these plant locations is uniform.)

For the turbine and reactor building plant locations, the FIVE methodology recommends that the exact distribution of electrical cabinets be determined and that the ratio of cabinets in a fire area/compartment to the total in that building (turbine or reactor) serve as the weighting factor.

It was determined that this is an unnecessary sophistication. If this type of refinement were to be truly accurate, there would need to be consideration of factors such as the number of breakers or cubicles in each panel and the energy (load/voltage) of the panel. A load distribution (frequency of demand) analysis would also be required to accurately spread the aggregate risk (inherent in the single baseline ignition frequency from the EPRI database) of ignition between individual panels. Instead, it has been assumed that, like the other five plant locations, the distribution of electrical cabinets in these plant locations is uniform and no weighting factor is required.

<u>Pumps</u>
Pumps are the next most common ignition source, with five types of pumps being listed for three plant locations. The number of pumps in each category was identified as to the plantwide total and where they were located. The ignition source weighting factor was then determined in accordance with the methodology indicated in the third column of FIVE Reference Table 1.2.

<u>Other Sources</u>
All other plant location specific ignition sources were associated with only a single plant location. These sources were:

Diesel Generators
Batteries
Fire Pumps
Other Pumps in the Intake Structure
Turbine Generator Excitor
Turbine Generator Oil
Turbine Generator Hydrogen
Main Feedwater Pumps
Other Pumps in the Turbine Building
Boiler(s)

The number of components in each category was identified as to the total and where they were located (i.e., which compartments within the total number of compartments for that plant location). The ignition source weighting factor was then determined in accordance with the methodology indicated in the third column of FIVE Reference Table 1.2.

4.1.3 Plantwide Ignition Sources

Table 1.2 of FIVE Attachment 10.3 lists the 18 plantwide fire ignition and/or fuel sources. These particular ignition sources were selected because they were identified/identifiable in the

EPRI database. In addition, this table lists the methodology for determining the weighting factors associated with each hazard and the baseline fire frequency based on the EPRI fire reporting database (and other sources).

Six of the 18 ignition/fuel sources were not included in the NMP2 analysis since they were not present. See Section 4.1.3.2 for the justification for each of the six items. Sections 4.1.3.1 below describes how the information for each of the 12 included plantwide ignition/fuel sources was applied/determined at NMP2.

4.1.3.1 Plantwide Sources Included

<u>Transformers</u>
A total of 90 transformers were identified during the plant walkdown. Only stand alone transformers were counted, there was no attempt to determine the number of built-in transformers (internal to electrical equipment). This number was verified by review of a NMP2 Master Equipment List (MEL) sort of all transformers in the database for the areas inspected during the walkdown. The total number was then increased to 167 to reflect those in the Radwaste Building (which was not inspected at all since the entire structure screened out in Phase I of the FIVE analysis) and other areas which were inaccessible during the plant walkdown.

<u>Hot Work Ignition of Transients</u>
Hot work ignition of fixed or transient combustibles was considered credible and was included in the ignition frequency analysis for all fire areas/compartments. It would be possible to argue that this factor could be eliminated for high radiation areas since work would be unlikely in these areas. (In addition, there would be little potential for storage of transient combustibles in these areas.) The weighting factor was the reciprocal of the total number of fire areas/compartments in the plant (157).

<u>Hot Work Ignition of Fixed Cables</u>
Hot work ignition of (exposed) fixed cables was postulated in every fire area/compartment which contained an entry for cable insulation in the fire loading analysis (USAR[6] Tables 9A.3-1 through 9A.3-12). The weighting factor was the reciprocal of the total number of fire areas/compartments in the plant (157).

<u>Transient Ignition Sources</u>
Note D in Table 1.2 of FIVE lists six potential transient ignition sources. Four of these are procedurally prohibited and/or have never been used at NMP2. These four sources being eliminated from consideration in this analysis are:

Cigarette Smoking - This is banned in all plant buildings (except for a smoking area for the plant operators), not just inside radiologically controlled areas.

Heaters - The use of heaters is banned in all plant areas except administrative (office) areas since all other plant areas have thermostatically controlled electric resistance heaters and fans in them (in addition to heating elements in the normal forced air ventilation systems). The one known instance of portable heaters being used in a plant area was conducted under a hot work permit and a fire watch was posted during the operation. This was a one time occurrence which is not expected to be repeated.

Candles - The use of candles is procedurally prohibited in all plant areas.

Overheating - The FIVE Methodology (Note D in the reference table) indicates that this is meant to address high flash point (and presumably high viscosity) items which must be heated before use. The example given is battery terminal grease. The NMP2 Fire Protection Supervisor indicated that none of the preventive maintenance products (greases or other lubricants) requires pre-heating before application. There was one special operation for coating terminals for new end batteries which required heating a material into which the terminal was dipped. This unusual occurrence was performed under a hot work permit and a fire watch was posted during the operation.

Two of the six transient ignition sources are found throughout NMP2, extension cords and hot pipes. As there are no restrictions on the use of extension cords they are considered to be present in all fire areas/compartments. All areas with steam lines are considered to have the "hot pipe" ignition source, even if the lines are only active occasionally.

The ignition frequency of 1.3×10^{-3} in FIVE is based on only a single fire incident, while the various weighting factors account for the relative frequency of the 13 fire incidents in the EPRI database caused by transient ignition sources. The weighting factor at NMP2, in accordance with the FIVE instructions, is 4 for most areas and 5 for areas which have steam lines.

Ventilation Subsystem Components (Fans)
A total of 111 fans were identified (observed) during the plant walkdown. Only fans which are components of the general plant ventilation systems were counted, there was no attempt to determine the number of built-in fans (internal to electrical equipment).

NOTE: The thermostat controlled electric resistance heating units (unit heaters) found in most NMP2 industrial areas were not included as there have been no fire incidents (major or minor) involving these units. In addition, the fans in these units are quite small and are much less likely to result in a fire which propagates beyond the unit itself then the larger fans in area ventilation systems.

The number of fans observed during the plant walkdown was verified by review of the NMP2 calculation for fire load due to electric motors (FPW-019). The total number was then increased to 220 to reflect those in the Radwaste Building (which was not inspected at all since the entire structure screened out in Phase I of the FIVE analysis), some which were not observed during the plant walkdown of accessible areas and other areas which were inaccessible during the plant walkdown.

Splices/junction Boxes in Appendix R Cables

In accordance with the FIVE methodology, the ignition hazard associated with splices or junction boxes in qualified cables was determined only for areas with Appendix R cable. The weighting factor was calculated by dividing the amount of exposed cabling in areas with Appendix R equipment by the total amount in all Appendix R areas. A review of the weighting factors shows that the FIVE decision not to address non-Appendix R areas is probably justified by the fact that the overwhelming amount of plant cable is found in the Reactor Building and cable tunnels and that the weighting factor (percentage) for other areas is very small and that this ignition source is not a significant contributor to the overall fire frequency in these other plant areas/compartments.

MG Sets

A total of four motor generator (MG) sets (2 sets of 2) were identified during the plant walkdown. Although the FIVE Methodology explicitly lists only MG sets for the Reactor Protection System (RPS), it is assumed that the initiation frequency is equally valid for any MG set.

Off-gas/hydrogen Recombiner

A total of three off-gas/hydrogen recombiners were identified during the plant walkdown (one in the Turbine Building off-gas area and one in each half of the Reactor Building).

Air Compressors

A total of 17 air compressors were identified during the plant walkdown. Included in this number were HVAC chiller compressors since they present a hazard similar to an air compressor. The number of compressors observed during the plant walkdown was verified by review of an NMP2 Master Equipment List (MEL) sort of all compressors in the database for the areas inspected during the walkdown. The total number was then increased to 24 to reflect those in areas which were inaccessible during the plant walkdown.

Elevator Motors

A total of four elevator motor rooms were identified during the plant walkdown, three in the Turbine Building and one in the South half of the Reactor Building.

Dryers

It is not clear from the EPRI report whether the term "dryers" refers to the electric heating element in laundry type dryers, steam powered or chemical desiccant air dryers, electric motors associated with either type of dryer or some combination. It will be assumed that the hazard associated with steam dryers is already addressed in the "hot pipe" ignition source frequency and there is no fire hazard associated with chemical desiccants once they are placed in their containers in the air system. Therefore, only electric motors associated with dryers will be counted for this ignition source.

Although no dryers were observed during the plant walkdown, a review of the NMP2 calculation for the fire load due to motor insulation (FPW-019) revealed a total of 5 dryer motors in two Turbine Building areas (neither of which was accessible during the walkdown).

Battery Chargers

A total of 13 battery chargers were identified during the plant walkdown. The number of chargers observed during the plant walkdown was verified by review of an NMP2 Master Equipment List (MEL) sort of all battery chargers in the database for the areas inspected during the walkdown. The total number was then increased to 14 to reflect a forklift battery charger in the Radwaste Building (which was not inspected at all since the entire structure screened out in Phase I of the FIVE analysis).

4.1.3.2 Plantwide Sources Not Included in Analysis

The following six potential ignition sources listed in the reference table were not included in the NMP2 analysis for the reasons listed.

Fire panels - Fire panels were not included because there have been no fire panel fires at NMP2. The inclusion of this source in the FIVE Methodology is based on only two fire reports in the EPRI database and these are potentially much older equipment using relays rather than solid state electronics (NMP2 does use relays as the final activating device). In addition, the majority of fire panels at NMP2 are located in stairwells where there are no fixed combustibles to spread the fire and there is little potential for the presence of plant trip initiators.

Non-rated cable runs - These have not been included because all cable purchased and installed in the NMP2 power block was IEEE 383 qualified with the exception of a small amount of cabling installed to provide a network of security video cameras.

Splices or junction boxes in non-rated cable runs - These have not been included because all cable purchased and installed in the NMP2 power block was IEEE 383 qualified with the exception of a small amount of cabling installed to provide a network of security video cameras.

Hydrogen tanks - These have not been included because the hydrogen storage tanks for NMP2 are located outside. (Small compressed gas cylinders are located in the plant to test/calibrate instrumentation but are not considered to be the hazard referred to in the FIVE Methodology.)

Hydrogen piping - This has not been included because the hydrogen piping for NMP2 is not normally pressurized and hydrogen make-up is required only once every other day (performed on the back shift). This risk is further discussed in Section 4.8.

Gas turbines - These have not been included because there are no gas turbines at NMP2.

Table 4.1-1 Fire Ignition Frequency Development Summary

Area	Zone		Description	Location Specific					Plant Wide			Total Freq
				Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
01	201	SW	N Aux Bay - 175 W Side	RB	Elec Cab	1	24	2.08E-03	Transient	5	4.14E-05	4.79E-03
					Pumps	4	43	2.32E-03	Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									Ventil/Fan	2	8.23E-05	
									JB/Splice	16150	1.50E-06	
01	202	SW	N Aux Bay - 175 Center	RB	Elec Cab	1	24	2.08E-03	Transient	5	4.14E-05	3.05E-03
					Pump	1	43	5.81E-04	Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									Ventil/Fan	2	8.23E-05	
									JB/Splice	18516	1.71E-06	
01	203	SW	N Aux Bay - 175 E Side	RB	Elec Cab	1	24	2.08E-03	Transient	5	4.14E-05	2.42E-03
									Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									Ventil/Fan	1	4.11E-05	
									JB/Splice	9972	9.23E-07	
01	211	SW	N Aux Bay - 198	RB	Elec Cab	1	24	2.08E-03	Transient	4	3.31E-05	2.42E-03
									Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									Ventil/Fan	1	4.11E-05	
									JB/Splice	50760	4.70E-06	
01	221	SW	N Aux Bay - 215	RB	None				Transient	4	3.31E-05	3.10E-04
									Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									JB/Splice	206712	1.91E-05	
01	231	SW	N Aux Bay - 240	SWGR	Elec Cab	1	1	9.45E-04	Transient	4	2.09E-06	9.86E-04

Table 4.1-1 Fire Ignition Frequency Development Summary												
Area	Zone	Description	Location Specific					Plant Wide			Total Freq
			Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
								Weld/Ord	1	1.24E-05	
								Weld/Cab	1	3.78E-06	
								Transformers	6	1.79E-05	
								Ventil/Fan	2	5.18E-06	
02	204 SW	RCIC Pump Room	RB	Elec Cab	1	24	2.08E-03	Transient	5	4.14E-05	4.15E-03
				Pumps	3	43	1.74E-03	Weld/Ord	1	1.97E-04	
								Ventil/Fan	2	8.23E-05	
03	206 SW	S Aux Bay - 175 W Side	RB	Elec Cab	1	24	2.08E-03	Transient	5	4.14E-05	2.42E-03
								Weld/Ord	1	1.97E-04	
								Weld/Cab	1	6.00E-05	
								Ventil/Fan	1	4.11E-05	
								JB/Splice	11880	1.10E-06	
03	207 SW	S Aux Bay - 175 Center	RB	Elec Cab	1	24	2.08E-03	Transient	5	4.14E-05	4.21E-03
				Pumps	3	43	1.74E-03	Weld/Ord	1	1.97E-04	
								Weld/Cab	1	6.00E-05	
								Ventil/Fan	2	8.23E-05	
								JB/Splice	23256	2.15E-06	
03	208 SW	S Aux Bay - 175 E Side	RB	Elec Cab	1	24	2.08E-03	Transient	5	4.14E-05	3.63E-03
				Pumps	2	43	1.16E-03	Weld/Ord	1	1.97E-04	
								Weld/Cab	1	6.00E-05	
								Ventil/Fan	2	8.23E-05	
								JB/Splice	18984	1.76E-06	
03	214 SW	S Aux Bay - 198	RB	None				Transient	4	3.31E-05	3.36E-04
								Weld/Ord	1	1.97E-04	
								Weld/Cab	1	6.00E-05	

Table 4.1-1 Fire Ignition Frequency Development Summary													
Area	Zone		Description	Location Specific					Plant Wide			Total Freq
				Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
									Ventil/Fan	1	4.11E-05	
									JB/Splice	50748	4.70E-06	
03	224	SW	S Aux Bay - 215	RB	Elec Cab	1	24	2.08E-03	Transient	4	3.31E-05	2.39E-03
									Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									JB/Splice	218016	2.02E-05	
03	239	SW	S Aux Bay - 240	SWGR	Elec Cab	1	1	9.45E-04	Transient	4	2.09E-06	9.82E-04
									Weld/Ord	1	1.24E-05	
									Weld/Cab	1	3.78E-06	
									Transformers	4	1.19E-05	
									Ventil/Fan	2	5.18E-06	
									JB/Splice	196032	1.14E-06	
04	205	NZ	HPCS Pump Room	RB	Elec Cab	1	24	2.08E-03	Transient	5	4.14E-05	4.73E-03
					Pumps	4	43	2.33E-03	Weld/Ord	1	1.97E-04	
									Ventil/Fan	2	8.23E-05	
05	234	NZ	Drywell	DW	Inerted				Inerted			NA
08	301	NW	140 Degree Cable Tunnel - EL 214	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.52E-04
									Weld/Ord	1	8.29E-06	
									Weld/Cab	1	2.52E-06	
									JB/Splice	1296204	5.04E-06	
08	302	NW	35 deg Elec Tunnel W of Rx Bldg - EL 214	CSR	None				Transient	4	1.39E-06	1.44E-05
									Weld/Ord	1	8.29E-06	
									Weld/Cab	1	2.52E-06	
									JB/Splice	571980	2.22E-06	
10	303	NW	315 deg tunnel - EL 214	CSR	None				Transient	4	1.39E-06	1.22E-05

Table 4.1-1 Fire Ignition Frequency Development Summary													
Area	Zone		Description	Location Specific					Plant Wide			Total Freq
				Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
									Weld/Ord	1	8.29E-06	
									Weld/Cab	1	2.52E-06	
16	306.1	NW	Div I Cable Area - EL 214	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.55E-04
									Weld/Ord	1	8.29E-06	
									Weld/Cab	1	2.52E-06	
									Transformers	4	7.95E-06	
									JB/Splice	79380	3.09E-07	
16	306.2	NW	Document Storage Area - EL 214	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	5.26E-04
									Weld/Ord	1	1.97E-04	
16	312	NZ	Div II Cable Area	SWGR	Elec Cab	1	1	2.02E-04	Transient	4	2.09E-06	2.23E-04
									Weld/Ord	1	1.24E-05	
									Weld/Cab	1	3.78E-06	
									Transformers	1	2.98E-06	
									JB/Splice	19200	1.12E-07	
16	321	NW	Div I Riser Area	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.48E-04
									Weld/Ord	1	8.29E-06	
									Weld/Cab	1	2.52E-06	
									JB/Splice	253308	9.85E-07	
16	332	NW	Div I Cable Chase W	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.49E-04
									Weld/Ord	1	8.29E-06	
									Weld/Cab	1	2.52E-06	
									JB/Splice	590532	2.30E-06	
16	352	NW	Div I Cable Chase W	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.58E-04
									Weld/Ord	1	8.29E-06	
									Weld/Cab	1	2.52E-06	

Table 4.1-1 Fire Ignition Frequency Development Summary											
Area	Zone	Description	Location Specific					Plant Wide			Total Freq
			Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
								Transformers	5	9.93E-06	
								JB/Splice	306384	1.19E-06	
16	362.2 NZ	Pipe Tunnel - 245	INT	None				Transient	4	3.31E-05	2.31E-04
								Weld/Ord	1	1.97E-04	
16	371 NW	Div I Cable Chase W - EL 306	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.48E-04
								Weld/Ord	1	8.29E-06	
								Weld/Cab	1	2.52E-06	
								JB/Splice	248064	9.65E-07	
17	305 NW	Div I Riser Area	CSR	None				Transient	4	1.39E-06	1.27E-05
								Weld/Ord	1	8.29E-06	
								Weld/Cab	1	2.52E-06	
								JB/Splice	133692	5.20E-07	
17	322 NW	Div I Cable Routing Area	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.48E-04
								Weld/Ord	1	8.29E-06	
								Weld/Cab	1	2.52E-06	
								JB/Splice	386496	1.50E-06	
17	325 NW	Div I Cable Routing Area	CSR	None				Transient	4	1.39E-06	1.25E-05
								Weld/Ord	1	8.29E-06	
								Weld/Cab	1	2.52E-06	
								JB/Splice	75168	2.92E-07	
17	333 XL	Div I Stby SWGR Rm	SWGR	Elec Cab	1	1	9.45E-04	Transient	4	2.09E-06	9.78E-04
								Weld/Ord	1	1.24E-05	
								Weld/Cab	1	3.78E-06	
								Transformers	3	8.94E-06	
								Ventil/Fan	2	5.18E-06	

Table 4.1-1 Fire Ignition Frequency Development Summary										
Area Zone	Description	Location Specific					Plant Wide			Total Freq
		Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
							JB/Splice	104664	6.11E-07	
17 334 NZ	Div I Battery Room	BAT	Batteries	1	1	4.58E-04	Transient	4	4.74E-06	5.05E-04
							Weld/Ord	1	2.82E-05	
							Weld/Cab	1	8.58E-06	
							Ventil/Fan	1	5.88E-06	
							JB/Splice	6324	8.37E-08	
17 343 NZ	Remote Shutdown Rm A	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.46E-04
							Weld/Ord	1	8.29E-06	
							Ventil/Fan	1	1.73E-06	
17 None XX	Fire Protection Valve Rm	INT	None				Transient	4	3.31E-05	2.31E-04
							Weld/Ord	1	1.97E-04	
18 304 NW	230 Degree Cable Tunnel	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.49E-04
							Weld/Ord	1	8.29E-06	
							Weld/Cab	1	2.52E-06	
							JB/Splice	510012	1.98E-06	
18 309 NW	Cable Chase - Div II	CSR	None				Transient	4	1.39E-06	1.28E-05
							Weld/Ord	1	8.29E-06	
							Weld/Cab	1	2.52E-06	
							JB/Splice	153480	5.97E-07	
18 324 NW	Div II Cable Riser Area	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.50E-04
							Weld/Ord	1	8.29E-06	
							Weld/Cab	1	2.52E-06	
							Transformers	1	1.99E-06	
							JB/Splice	244908	9.52E-07	
18 337 NW	Div 2/3 Cable Chase	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.49E-04

Table 4.1-1 Fire Ignition Frequency Development Summary

Area	Zone		Description	Location Specific Bldg	Source	Qty	LT	Freq	Plant Wide Source	Qty	Freq	Total Freq
									Weld/Ord	1	8.29E-06	
									Weld/Cab	1	2.52E-06	
									JB/Splice	507792	1.97E-06	
18	359	NW	Div 2/3 Cable Chase	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.55E-04
									Weld/Ord	1	8.29E-06	
									Weld/Cab	1	2.52E-06	
									Transformers	3	5.96E-06	
									Ventil/Fan	1	1.73E-06	
									JB/Splice	181080	7.04E-07	
18	377	NW	Div 2/3 Cable Chase - EL 306	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.47E-04
									Weld/Ord	1	8.29E-06	
									Weld/Cab	1	2.52E-06	
									JB/Splice	107580	4.18E-07	
19	323	NW	Div II Cable Routing Area	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.48E-04
									Weld/Ord	1	8.29E-06	
									Weld/Cab	1	2.52E-06	
									JB/Splice	451920	1.76E-06	
19	326	NW	Div II Cable Routing Area	CSR	None				Transient	4	1.39E-06	1.25E-05
									Weld/Ord	1	8.29E-06	
									Weld/Cab	1	2.52E-06	
									JB/Splice	75888	2.95E-07	
19	335	NZ	Div II Battery Room	BAT	Batteries	1	1	4.58E-04	Transient	4	4.74E-06	5.05E-04
									Weld/Ord	1	2.82E-05	
									Weld/Cab	1	8.58E-06	
									Ventil/Fan	1	5.88E-06	

Table 4.1-1 Fire Ignition Frequency Development Summary													
Area	Zone		Description	Location Specific					Plant Wide			Total Freq
				Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
									JB/Splice	6324	8.37E-08	
19	336	XL	Div II Stby SWGR Rm	SWGR	Elec Cab	1	1	9.45E-04	Transient	4	2.09E-06	9.69E-04
									Weld/Ord	1	1.24E-05	
									Weld/Cab	1	3.78E-06	
									Ventil/Fan	2	5.18E-06	
									JB/Splice	158136	9.22E-07	
19	338	NZ	Remote Shutdown Rm B	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.46E-04
									Weld/Ord	1	8.29E-06	
									Ventil/Fan	1	1.73E-06	
21	327	NW	HPCS Cable Routing Area	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.47E-04
									Weld/Ord	1	8.29E-06	
									Weld/Cab	1	2.52E-06	
									JB/Splice	124452	4.84E-07	
21	342	XL	HPCS SWGR	SWGR	Elec Cab	1	1	9.45E-04	Transient	4	2.09E-06	9.77E-04
									Weld/Ord	1	1.24E-05	
									Transformers	5	1.49E-05	
									Ventil/Fan	1	2.59E-06	
									JB/Splice	8628	5.03E-08	
22	340	NZ	Div I Chiller Rm	RB	Elec Cab	1	24	2.08E-03	Transient	4	3.31E-05	3.80E-03
					Other Pump	2	43	1.16E-03	Weld/Ord	1	1.97E-04	
									Ventil/Fan	3	1.23E-04	
									Air Comp	1	1.96E-04	
23	341	NZ	Div II Chiller Rm	RB	Elec Cab	1	24	2.08E-03	Transient	4	3.31E-05	3.75E-03
					Other Pump	2	43	1.16E-03	Weld/Ord	1	1.97E-04	
									Ventil/Fan	2	8.23E-05	

Table 4.1-1 Fire Ignition Frequency Development Summary													
Area	Zone		Description	Location Specific					Plant Wide			Total Freq
				Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
									Air Comp	1	1.96E-04	
24	356	NZ	PGCC Relay Rm	SWGR	Elec Cab	1	1	2.02E-04	Transient	4	2.09E-06	2.25E-04
									Weld/Ord	1	1.24E-05	
									Weld/Cab	1	3.78E-06	
									JB/Splice	910080	5.31E-06	
24	357	XG	Plant Computer Rm	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.50E-04
									Weld/Ord	1	8.29E-06	
									Weld/Cab	1	2.52E-06	
									Ventil/Fan	1	1.73E-06	
									JB/Splice	404448	1.57E-06	
25	360	NZ	Div I CR HVAC Rm	RB	Elec Cab	1	24	2.08E-03	Transient	4	3.31E-05	2.77E-03
									Weld/Ord	1	1.97E-04	
									Ventil/Fan	11	4.52E-04	
26	373.1	NZ	Plant Control Rm	CR	Elec Cab	1	1	9.50E-03	Transient	4	3.31E-05	9.94E-03
									Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									JB/Splice	1596168	1.48E-04	
26	373.2	NZ	Shift Supervisor Office	CR	None				Transient	4	3.31E-05	2.31E-04
									Weld/Ord	1	1.97E-04	
26	373.3	NZ	Training Rm	CR	None				Transient	4	3.31E-05	2.31E-04
									Weld/Ord	1	1.97E-04	
27	378	NZ	Div II CR HVAC Rm	RB	Elec Cab	1	24	2.08E-03	Transient	4	3.31E-05	2.52E-03
									Weld/Ord	1	1.97E-04	
									Ventil/Fan	5	2.06E-04	
28	401.1	NZ	Div I DG Cont Rm	DG	Elec Cab	1	1	2.40E-03	Transient	4	3.31E-05	2.71E-03

Table 4.1-1 Fire Ignition Frequency Development Summary													
Area	Zone		Description	Location Specific					Plant Wide			Total Freq
				Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
									Weld/Ord	1	1.97E-04	
									Ventil/Fan	2	8.23E-05	
28	402.1	SW	Div I Diesel	DG	Elec Cab	1	1	2.40E-03	Transient	4	3.31E-05	2.91E-02
					Diesel Gen	1	1	2.60E-02	Weld/Ord	1	1.97E-04	
									Ventil/Fan	3	1.23E-04	
									Air Comp	2	3.92E-04	
29	401.2	NZ	Div II DG Cont Rm	DG	Elec Cab	1	1	2.40E-03	Transient	4	3.31E-05	2.71E-03
									Weld/Ord	1	1.97E-04	
									Ventil/Fan	2	8.23E-05	
29	403.1	SW	Div II Diesel	DG	Elec Cab	1	1	2.40E-03	Transient	4	3.31E-05	2.91E-02
					Diesel Gen	1	1	2.60E-02	Weld/Ord	1	1.97E-04	
									Ventil/Fan	3	1.23E-04	
									Air Comp	2	3.92E-04	
30	401.3	NZ	HPCS DG Cont Rm	DG	Elec Cab	1	1	2.40E-03	Transient	4	3.31E-05	2.71E-03
									Weld/Ord	1	1.97E-04	
									Ventil/Fan	2	8.23E-05	
30	404.1	SW	HPCS Diesel	DG	Elec Cab	1	1	2.40E-03	Transient	4	3.31E-05	2.91E-02
					Diesel Gen	1	1	2.60E-02	Weld/Ord	1	1.97E-04	
									Ventil/Fan	3	1.23E-04	
									Air Comp	2	3.92E-04	
34			N Half Rx Bldg	RB	Elec Cab	1	24	2.08E-03	Transient	5	4.14E-05	3.90E-02
					Pumps	11	43	6.40E-03	Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									Transformers	6	2.84E-04	
									Ventil/Fan	10	4.11E-04	

Table 4.1-1 Fire Ignition Frequency Development Summary											
Area Zone		Description	Location Specific					Plant Wide			Total Freq
			Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
								JB/Splice	2726604	2.52E-04	
								H2 Recom	1	2.87E-02	
								Air Comp	3	5.88E-04	
34	242 NW	Track Bay	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	5.26E-04
								Weld/Ord	1	1.97E-04	
35		S Half Rx Bldg	RB	Elec Cab	1	24	2.08E-03	Transient	5	4.14E-05	3.84E-02
				Pumps	7	43	4.07E-03	Weld/Ord	1	1.97E-04	
								Weld/Cab	1	6.00E-05	
								Transformers	12	5.68E-04	
								Ventil/Fan	13	5.35E-04	
								JB/Splice	2383440	2.21E-04	
								H2 Recom	1	2.87E-02	
								Air Comp	2	3.92E-04	
								Elev Motor	1	1.58E-03	
38	311 NZ	Computer Battery Room	BAT	Batteries	1	1	4.58E-04	Transient	4	4.74E-06	5.05E-04
								Weld/Ord	1	2.82E-05	
								Weld/Cab	1	8.58E-06	
								Ventil/Fan	1	5.88E-06	
39	307 NZ	Div I W Battery Room	BAT	Batteries	1	1	4.58E-04	Transient	4	4.74E-06	4.96E-04
								Weld/Ord	1	2.82E-05	
								Ventil/Fan	1	5.88E-06	
40	308 NZ	Div II E Battery Room	BAT	Batteries	1	1	4.58E-04	Transient	4	4.74E-06	4.96E-04
								Weld/Ord	1	2.82E-05	
								Ventil/Fan	1	5.88E-06	
42	708 NW	Oil Storage Rm	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	3.76E-03

Table 4.1-1 Fire Ignition Frequency Development Summary												
Area	Zone		Description	Location Specific					Plant Wide			Total Freq
				Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
					T/G Oil	1	5	2.60E-03	Weld/Ord	1	1.97E-04	
					Other Pumps	3	32	5.91E-04	Transformers	1	4.73E-05	
48	236	NZ	HVAC Room - Div I	RB	Elec Cab	1	24	2.08E-03	Transient	4	3.31E-05	2.40E-03
									Weld/Ord	1	1.97E-04	
									Ventil/Fan	2	8.23E-05	
49	701	NW	Railroad Track Bay	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	5.26E-04
									Weld/Ord	1	1.97E-04	
49	Chwtr	XX	Chilled Water Structure	INT	Elec Cab	1	1	2.40E-03	Transient	4	3.31E-05	6.04E-03
					Other Pumps	4	4	3.20E-03	Weld/Ord	1	1.97E-04	
									Ventil/Fan	5	2.06E-04	
50	256	NZ	Main Steam Tunnel	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	6.17E-04
									Weld/Ord	1	1.97E-04	
									Ventil/Fan	2	8.23E-05	
50	702	NZ	Off-Gas Area	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	3.58E-02
									Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									Transformers	2	9.46E-05	
									Ventil/Fan	1	4.11E-05	
									H2 Recom	1	2.87E-02	
									Dryers	3	5.22E-03	
									Air Comp	6	1.17E-03	
50	703	NZ	Regen/Demin Area & CR	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	8.32E-04
					Other Pump	1	32	1.97E-04	Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									Ventil/Fan	1	4.11E-05	

Table 4.1-1 Fire Ignition Frequency Development Summary													
Area	Zone		Description	Location Specific					Plant Wide			Total Freq
				Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
50	704	NZ	Heater Bay A - 250' El	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	8.73E-04
					Other Pump	1	32	1.97E-04	Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									Ventil/Fan	2	8.23E-05	
50	705	NZ	Heater Bay B - 250' El	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	8.73E-04
					Other Pump	1	32	1.97E-04	Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									Ventil/Fan	2	8.23E-05	
50	706	NZ	Heater Bay C - 250' El	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	8.73E-04
					Other Pump	1	32	1.97E-04	Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									Ventil/Fan	2	8.23E-05	
50	707	SW	Truck Aisle	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	5.86E-04
									Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
50	709	NZ	Instrument Air Rm	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	4.97E-03
									Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									Ventil/Fan	3	1.23E-04	
									Air Comp	4	7.83E-04	
									Dryers	2	3.48E-03	
50	716+	SW	General Area Turb Bldg 250	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	1.26E-02
	717+				T/G Oil	1	5	2.60E-03	Weld/Ord	1	1.97E-04	
	718				T/G Hydrogen	1	3	1.83E-03	Weld/Cab	1	6.00E-05	
					Other Pumps	11	32	2.17E-03	Transformers	16	7.57E-04	

Table 4.1-1 Fire Ignition Frequency Development Summary											
Area	Zone	Description	Location Specific					Plant Wide			Total Freq
			Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
				MF Pumps	3	3	4.00E-03	Ventil/Fan	15	6.17E-04	
50	721 NZ	Charcoal Adsorber Area	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	5.86E-04
								Weld/Ord	1	1.97E-04	
								Weld/Cab	1	6.00E-05	
50	722 NZ	Condensate Demin Area	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	7.91E-04
				Other Pump	1	32	1.97E-04	Weld/Ord	1	1.97E-04	
								Weld/Cab	1	6.00E-05	
50	723 NZ	Heater Bay A - 277' El	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	6.77E-04
								Weld/Ord	1	1.97E-04	
								Weld/Cab	1	6.00E-05	
								Ventil/Fan	2	8.23E-05	
50	724 NZ	Heater Bay B - 277' El	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	6.77E-04
								Weld/Ord	1	1.97E-04	
								Weld/Cab	1	6.00E-05	
								Ventil/Fan	2	8.23E-05	
50	725 NZ	Heater Bay C - 277' El	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	6.77E-04
								Weld/Ord	1	1.97E-04	
								Weld/Cab	1	6.00E-05	
								Ventil/Fan	2	8.23E-05	
50	727+ SW	General Area Turb Bldg 277	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	7.02E-03
	730+			T/G Oil	1	5	2.60E-03	Weld/Ord	1	1.97E-04	
	731			T/G Hydrogen	1	3	1.83E-03	Weld/Cab	1	6.00E-05	
								Transformers	29	1.37E-03	
								Ventil/Fan	15	6.17E-04	

Table 4.1-1 Fire Ignition Frequency Development Summary													
Area	Zone		Description	Location Specific					Plant Wide			Total Freq
				Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
50	728	NZ	Air Ejector Rm A	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	5.34E-04
									Weld/Ord	1	1.97E-04	
50	729	NZ	Air Ejector Rm B	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	5.34E-04
									Weld/Ord	1	1.97E-04	
50	751	NZ	Elevator Machine Rm #1	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	2.10E-03
									Weld/Ord	1	1.97E-04	
									Elev Motor	1	1.58E-03	
50	752.1	NZ	HVAC Equipment Rm - 288	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	1.10E-03
					Other Pumps	2	32	3.94E-04	Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									Ventil/Fan	3	1.23E-04	
50	752.2	NZ	HVAC Equipment Rm - 306	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	1.54E-03
					Other Pumps	4	32	7.88E-04	Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									Transformers	1	4.73E-05	
									Ventil/Fan	3	1.23E-04	
50	753	NZ	Elevator Machine Rm #3	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	2.11E-03
									Weld/Ord	1	1.97E-04	
									Elev Motor	1	1.58E-03	
50	754	NZ	Clean Steam Reboiler Rm A	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	5.75E-04
									Weld/Ord	1	1.97E-04	
									Ventil/Fan	1	4.11E-05	
50	755	NZ	Turbine Operating Floor	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	1.52E-02
					T/G Oil	1	5	2.60E-03	Weld/Ord	1	1.97E-04	
					T/G Hydrogen	1	3	1.83E-03	Weld/Cab	1	6.00E-05	

Table 4.1-1 Fire Ignition Frequency Development Summary													
Area	Zone		Description	Location Specific					Plant Wide			Total Freq
				Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
					T/G Hydrogen	1	1	5.50E-03	Transformers	6	2.84E-04	
					T/G Excitor	1	1	4.00E-03	Ventil/Fan	10	4.11E-04	
50	756	NZ	Clean Steam Reboiler Rm B	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	5.75E-04
									Weld/Ord	1	1.97E-04	
									Ventil/Fan	1	4.11E-05	
50	762	NZ	Health Physics Storage	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	5.26E-04
									Weld/Ord	.1	1.97E-04	
50	763	NZ	Elevator Machine Rm #2	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	2.11E-03
									Weld/Ord	1	1.97E-04	
									Elev Motor	1	1.58E-03	
50	764	NZ	Contam Instrument Rm	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	5.26E-04
									Weld/Ord	1	1.97E-04	
51	601	XL	W Normal SWGR Rm - EL 237	SWGR	Elec Cab	1	1	9.45E-04	Transient	4	2.09E-06	9.69E-04
									Weld/Ord	1	1.24E-05	
									Weld/Cab	1	3.78E-06	
									Transformers	2	5.96E-06	
52	602	XL	E Normal SWGR Rm - EL 237	SWGR	Elec Cab	1	1	9.45E-04	Transient	4	2.09E-06	1.16E-03
									Weld/Ord	1	1.24E-05	
									Weld/Cab	1	3.78E-06	
									Transformers	8	2.38E-05	
									MG Sets	2	1.73E-04	
52	604	NZ	Security Storage Rm - EL 237	SWGR	Elec Cab	1	1	9.45E-04	Transient	4	2.09E-06	9.60E-04
									Weld/Ord	1	1.24E-05	
53	603	NZ	Battery Rms - EL 237	BAT	Batteries	1	1	4.58E-04	Transient	4	4.74E-06	4.91E-04
									Weld/Ord	1	2.82E-05	

Table 4.1-1 Fire Ignition Frequency Development Summary													
Area	Zone		Description	Location Specific					Plant Wide			Total Freq
				Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
55	237	NZ	DIV II Elec Tunnel HVAC	RB	Elec Cab	1	24	2.08E-03	Transient	4	3.31E-05	2.40E-03
									Weld/Ord	1	1.97E-04	
									Ventil/Fan	2	8.23E-05	
55	361	NZ	Pipe Tunnel S End of Turb	INT	None				Transient	4	3.31E-05	2.31E-04
									Weld/Ord	1	1.97E-04	
55	362.1	NZ	Pipe Tunnel E End of Turb	INT	None				Transient	4	3.31E-05	2.31E-04
									Weld/Ord	1	1.97E-04	
55	363	NZ	Pipe Tunnel NW End of Turb	INT	None				Transient	4	3.31E-05	2.31E-04
									Weld/Ord	1	1.97E-04	
55	811	NZ	SWP Int/Disch Pit Area	INT	None				Transient	4	3.31E-05	2.31E-04
									Weld/Ord	1	1.97E-04	
55	902	NW	Cond Storage Tanks	INT	Elec Cab	1	1	2.40E-03	Transient	4	3.31E-05	2.71E-03
									Weld/Ord	1	1.97E-04	
									Ventil/Fan	2	8.23E-05	
57	961	NW	Asphalt Tank and Pumps	RAD	Mics Comps	1	1	7.22E-04	Transient	4	2.75E-06	7.41E-04
									Weld/Ord	1	1.64E-05	
58	901	NZ	Radwaste General Area - 261	RAD	Mics Comps	1	1	7.22E-04	Transient	4	2.75E-06	7.46E-04
									Weld/Ord	1	1.64E-05	
									Weld/Cab	1	4.98E-06	
58	904	NZ	Radwaste Evaporator Area	RAD	Mics Comps	1	1	7.22E-04	Transient	4	2.75E-06	7.41E-04
									Weld/Ord	1	1.64E-05	
58	906	NZ	Radwaste General Area - 279	RAD	Mics Comps	1	1	7.22E-04	Transient	4	2.75E-06	7.66E-04
									Weld/Ord	1	1.64E-05	
									Weld/Cab	1	4.98E-06	
									Transformers	5	1.96E-05	

Table 4.1-1 Fire Ignition Frequency Development Summary													
Area	Zone		Description	Location Specific					Plant Wide			Total Freq
				Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
58	911	NW	Radwaste Tanks & Ventil Area	RAD	Mics Comps	1	1	7.22E-04	Transient	4	2.75E-06	7.90E-04
									Weld/Ord	1	1.64E-05	
									Weld/Cab	1	4.98E-06	
									Transformers	5	1.96E-05	
									Ventil/Fan	7	2.39E-05	
58	941	NW	Radwaste General Area - 240	RAD	Mics Comps	1	1	7.22E-04	Transient	4	2.75E-06	7.62E-04
									Weld/Ord	1	1.64E-05	
									Weld/Cab	1	4.98E-06	
									Transformers	4	1.57E-05	
59	908	NZ	Waste Solidif & Storage	RAD	Mics Comps	1	1	7.22E-04	Transient	4	2.75E-06	7.41E-04
									Weld/Ord	1	1.64E-05	
59	921	SW	Radwaste Compactor Area	RAD	Mics Comps	1	1	7.22E-04	Transient	4	2.75E-06	7.45E-04
									Weld/Ord	1	1.64E-05	
									Transformers	1	3.93E-06	
59	951	NW	Truck Load & WSS Storage	RAD	Mics Comps	1	1	7.22E-04	Transient	4	2.75E-06	7.53E-04
									Weld/Ord	1	1.64E-05	
									Transformers	2	7.85E-06	
									Ventil/Fan	1	3.41E-06	
60	807	NZ	Service Water Pump B	INT	Elec Cab	1	1	2.40E-03	Transient	4	3.31E-05	5.98E-03
					SWP Pumps	3	3	3.20E-03	Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									Ventil/Fan	2	8.23E-05	
									JB/Splice	48912	4.53E-06	
60	808	NZ	Auxiliary Boiler Bldg	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	2.96E-03
					Boiler	1	1	1.60E-03	Weld/Ord	1	1.97E-04	

Table 4.1-1 Fire Ignition Frequency Development Summary											
Area Zone		Description	Location Specific					Plant Wide			Total Freq
			Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
				Other Pumps	3	32	5.91E-04	Weld/Cab	1	6.00E-05	
								Transformers	2	9.46E-05	
								Ventil/Fan	2	8.23E-05	
61	806 NZ	Service Water Pump A	INT	Elec Cab	1	1	2.40E-03	Transient	4	3.31E-05	5.98E-03
				SWP Pumps	3	3	3.20E-03	Weld/Ord	1	1.97E-04	
								Weld/Cab	1	6.00E-05	
								Ventil/Fan	2	8.23E-05	
								JB/Splice	45324	4.20E-06	
62	804 NW	Diesel Fire Pump Rm	INT	Elec Cab	1	1	2.40E-03	Transient	4	3.31E-05	6.63E-03
				Fire Pump	1	1	4.00E-03	Weld/Ord	1	1.97E-04	
63	805 NZ	Electric Fire Pump Rm	INT	Elec Cab	1	1	2.40E-03	Transient	4	3.31E-05	6.67E-03
				Fire Pump	3	3	4.00E-03	Weld/Ord	1	1.97E-04	
								Ventil/Fan	1	4.11E-05	
64	715 NZ	Foam Pump Rm	INT	Elec Cab	1	1	2.40E-03	Transient	4	3.31E-05	5.83E-03
				Other Pump	1	1	3.20E-03	Weld/Ord	1	1.97E-04	
65	714 NW	I&C Shop	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	5.26E-04
								Weld/Ord	1	1.97E-04	
66	402.2 SW	Div I Diesel Day Tank	DG	None				Transient	4	3.31E-05	2.31E-04
								Weld/Ord	1	1.97E-04	
67	403.2 SW	Div II Diesel Day Tank	DG	None				Transient	4	3.31E-05	2.31E-04
								Weld/Ord	1	1.97E-04	
68	404.2 SW	HPCS Diesel Day Tank	DG	None				Transient	4	3.31E-05	2.31E-04
								Weld/Ord	1	1.97E-04	
69	801 NZ	Water Treatment Bldg	INT	Elec Cab	1	1	2.40E-03	Transient	4	3.31E-05	6.17E-03
				Other Pumps	2	2	3.20E-03	Weld/Ord	1	1.97E-04	

Table 4.1-1 Fire Ignition Frequency Development Summary													
Area	Zone		Description	Location Specific					Plant Wide			Total Freq
				Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
									Weld/Cab	1	6.00E-05	
									Ventil/Fan	2	8.23E-05	
									Air Comp	1	1.95E-04	
70	395	XL	Radwaste Switchgear Rm	SWGR	Elec Cab	1	1	9.45E-04	Transient	4	2.09E-06	9.78E-04
									Weld/Ord	1	1.24E-05	
									Weld/Cab	1	3.78E-06	
									Transformers	5	1.49E-05	
70	903	NZ	Decon Area HVAC Equip Rm	RAD	Mics Comps	1	1	7.22E-04	Transient	4	2.75E-06	7.75E-04
									Weld/Ord	1	1.64E-05	
									Ventil/Fan	10	3.41E-05	
70	905	NW	Decon Area & Dirty Shop	RAD	Mics Comps	1	1	7.22E-04	Transient	4	2.75E-06	7.55E-04
									Weld/Ord	1	1.64E-05	
									Ventil/Fan	4	1.37E-05	
70	907	NZ	Radwaste CR	RAD	Mics Comps	1	1	7.22E-04	Transient	4	2.75E-06	7.46E-04
									Weld/Ord	1	1.64E-05	
									Weld/Cab	1	4.98E-06	
71	803+	NZ	Screenwell Bldg - Gen Area	INT	Elec Cab	1	1	2.40E-03	Transient	4	3.31E-05	6.56E-03
	802				Other Pumps	20	20	3.20E-03	Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
									Transformers	2	9.46E-05	
									Ventil/Fan	10	4.11E-04	
									JB/Splice	1741200	1.61E-04	
72	351.1	NZ	Instrument Shop	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	5.26E-04
									Weld/Ord	1	1.97E-04	
72	351.2	NZ	Corridor	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	5.26E-04

Table 4.1-1 Fire Ignition Frequency Development Summary													
Area	Zone		Description	Location Specific					Plant Wide			Total Freq
				Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
									Weld/Ord	1	1.97E-04	
73	247	NZ	Standby Gas Treatment - B	RB	Elec Cab	1	24	2.08E-03	Transient	4	3.31E-05	2.40E-03
									Weld/Ord	1	1.97E-04	
									Transformers	1	4.73E-05	
									Ventil/Fan	1	4.11E-05	
74	248	NZ	Standby Gas Treatment - A	RB	Elec Cab	1	24	2.08E-03	Transient	4	3.31E-05	2.40E-03
									Weld/Ord	1	1.97E-04	
									Transformers	1	4.73E-05	
									Ventil/Fan	1	4.11E-05	
75	339	NZ	HPCS Battery Room	BAT	Batteries	1	1	4.58E-04	Transient	4	4.74E-06	4.96E-04
									Weld/Ord	1	2.82E-05	
									Ventil/Fan	1	5.88E-06	
76	380.1	NZ	Operator's Lounge	RB	Elec Cab	1	24	2.08E-03	Transient	4	3.31E-05	2.31E-03
									Weld/Ord	1	1.97E-04	
76	380.2	NZ	Corridor from CR to Lounge	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	5.26E-04
									Weld/Ord	1	1.97E-04	
									JB/Splice	432	4.00E-08	
77	621	NZ	Penthouse N SWGR Bldg	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	3.78E-03
									Weld/Ord	1	1.97E-04	
									Transformers	2	9.46E-05	
									Ventil/Fan	10	4.11E-04	
									MG Sets	2	2.75E-03	
78	612	XL	W Normal SWGR Rm EL 261	SWGR	Elec Cab	1	1	9.45E-04	Transient	4	2.09E-06	9.81E-04
									Weld/Ord	1	1.24E-05	
									Weld/Cab	1	3.78E-06	

Table 4.1-1 Fire Ignition Frequency Development Summary														
Area	Zone		Description	Location Specific					Plant Wide			Total Freq
				Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
									Transformers	6	1.79E-05	
79	613	XL	E Normal SWGR Rm	SWGR	Elec Cab	1	1	9.45E-04	Transient	4	2.09E-06	9.72E-04
			EL 261						Weld/Ord	1	1.24E-05	
									Weld/Cab	1	3.78E-06	
									Transformers	3	8.94E-06	
80	246	NW	Aux Service Bldg	TB	Elec Cab	1	44	2.95E-04	Transient	5	4.14E-05	5.94E-04
									Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
80	611	NW	Electric Bay	CSR	Elec Cab	1	1	1.34E-04	Transient	4	1.39E-06	1.49E-04
									Weld/Ord	1	8.29E-06	
									Weld/Cab	1	2.52E-06	
									Transformers	1	1.99E-06	
80	761.2	NZ	Clean Access Area	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	5.86E-04
									Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
80	761.3	NZ	Clean Access Area	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	5.86E-04
									Weld/Ord	1	1.97E-04	
									Weld/Cab	1	6.00E-05	
81	253	XL	600V SWGR Rm	SWGR	Elec Cab	1	1	9.45E-04	Transient	4	2.09E-06	9.63E-04
									Weld/Ord	1	1.24E-05	
									Weld/Cab	1	3.78E-06	
82	732	NW	Lube Oil Store Rm	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	3.97E-03
					T/G Oil	1	5	2.60E-03	Weld/Ord	1	1.97E-04	
					Other Pumps	4	32	7.88E-04	Weld/Cab	1	6.00E-05	
83	726	XL	Normal SWGR - East	SWGR	Elec Cab	1	1	9.45E-04	Transient	4	2.09E-06	9.81E-04

Table 4.1-1 Fire Ignition Frequency Development Summary											
Area	Zone	Description	Location Specific					Plant Wide			Total Freq
			Bldg	Source	Qty	LT	Freq	Source	Qty	Freq	
								Weld/Ord	1	1.24E-05	
								Weld/Cab	1	3.78E-06	
								Transformers	5	1.49E-05	
								Ventil/Fan	1	2.59E-06	
84	740 XL	Normal SWGR - West	SWGR	Elec Cab	1	1	9.45E-04	Transient	4	2.09E-06	9.75E-04
								Weld/Ord	1	1.24E-05	
								Weld/Cab	1	3.78E-06	
								Transformers	4	1.19E-05	
85	251 NW	Standby Gas Treatment	RB	Elec Cab	1	24	2.08E-03	Transient	4	3.31E-05	3.70E-03
				Pumps	2	43	1.16E-03	Weld/Ord	1	1.97E-04	
								Weld/Cab	1	6.00E-05	
								Ventil/Fan	4	1.65E-04	
86	274 SW	Resin Storage Area	RB	Elec Cab	1	24	2.08E-03	Transient	4	3.31E-05	2.31E-03
								Weld/Ord	1	1.97E-04	
86	770 NW	Cafeteria and Corridor	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	5.26E-04
								Weld/Ord	1	1.97E-04	
87	255 SW	Div I SFC Pump Rm	RB	Elec Cab	1	24	2.08E-03	Transient	4	3.31E-05	3.48E-03
				Pumps	2	43	1.16E-03	Weld/Ord	1	1.97E-04	
88	331 NW	Corridor	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	7.69E-04
								Weld/Ord	1	1.97E-04	
								Weld/Cab	1	6.00E-05	
								Transformers	3	1.42E-04	
								Ventil/Fan	1	4.11E-05	
90	761.1 NZ	Stairway Enclosure	TB	Elec Cab	1	44	2.95E-04	Transient	4	3.31E-05	5.26E-04
								Weld/Ord	1	1.97E-04	

4.2 Review of Plant Information and Walkdown

The following documents were reviewed and used in this analysis: NMP2 USAR[6], NMP2 IPE[1], various drawings, procedures, design specifications & criteria, and Appendix R analyses. These additional documents are referenced in tier 2 documents[27 thru 31]. Additionally, individuals involved in this analysis had plant specific experience in fire protection, IPE development and applications, fire hazard analysis, equipment qualification, and Appendix R analysis.

Several walkdowns were performed in support of the analysis. An initial walkdown (summarized below) was performed to investigate fire barriers, presence of ignition sources, and issues associated with the Sandia Risk Scoping Study[32]. Other walkdowns were performed in support of the screening and detailed analysis efforts. Some of the more important walkdowns are summarized in Section 4.6. Observations and conclusions from the other walkdowns are provided in Section 4.6, as appropriate.

<u>Initial Walkdown</u>
A plant walkdown was performed August 18-19, 1993. The objectives of the walkdown are summarized below:

- Ensure the fire barriers being credited were intact and the barriers between compartments being credited in the fire compartment interaction analysis were not compromised by the presence of continuous combustibles or other features which could result in fire propagation through non-rated barriers.

- Determine the presence of ignition sources in each fire area or compartment including:

    - transformers
    - dryers
    - battery chargers
    - HVAC system fans
    - air compressors (also included chiller compressors)
    - pumps
    - MG sets

- Investigate issues from the Sandia Risk Scoping Study, including:

    - Seismic actuation of fire suppression systems
    - Seismic damage of suppression systems causing unavailability of equipment
    - Seismically-induced fires involving flammable liquid tanks and/or piping

The initial walkdown was conducted by Robert C. Beller, P.E., Senior Fire Protection Engineer (Pacific Nuclear) and Gaines Bruce (NMPC Fire Protection Engineer). In addition, the walkdown was used to obtain information on:

- The fire barrier surveillance program, including the inspection of BOP barriers and corrective action requirements.

- The administrative controls which impact on the assumptions/credits given for transient ignition sources and other portions of the FIVE methodology.

The walkdown methodology consisted of a tour of all accessible plant areas. The NMPC personnel escorting the walkdown engineers had key card access to all plant areas, however, contaminated, high radiation, or locked areas were not entered. The presence of components, in these unvisited areas, which affect the fire ignition frequency was initially determined by a review of the fire loading calculation and the pre-fire plans. These numbers were later verified and augmented by the review of plant equipment database searches and the review of the plant fire loading basis calculation for electric motors, which encompasses fan, dryer and compressor motors.

An information checklist was prepared in advance to ensure that the required information was obtained in each compartment or area. The radwaste building was not inspected since the entire building was screened out before hand.

The results recorded on the walkdown checklists were tabulated, entered into the database[27] and are described in Sections 4.1 and 4.8. Many of the field observations are described in the various sections of this report as they were relevant to decisions on NMP2 specific deviations from the FIVE methodology's general approach.

4.3 Fire Growth and Propagation

Fire modeling using the FIVE[25] methodology was employed for the detailed fire risk evaluation of the various fire compartments at NMP2. The extent of the required detailed modeling was minimized by employing a generic modeling of typical combustibles (electrical cabinets, motors, transients, etc.). This allowed a screening to be employed during walkdowns of each fire compartment. Using this methodology, only scenarios that offered the potential for concern were identified and modeled. However, walkdown screening was successful in eliminating the need for detailed modeling in the majority of compartments. Modeling was also performed for the purpose of evaluating detection and suppression system response in a limited number of areas to support the detailed screening process.

Generic evaluations were performed for electrical cabinets, transformers, electric motors and transients. "In-The-Plume" evaluations for center, corner, and wall fire locations were performed for both damage and ignition scenarios and also for radiant exposure damage scenarios. These evaluations provided critical separation distances, or zone of influence distances, that were used to evaluate the potential involvement of adjacent combustibles from the various ignition sources as identified during plant walkdown of each fire compartment.

NMP2 utilizes IEEE 383 qualified cable. Therefore, a damage temperature of 700°F was used in the evaluations and a temperature of 932°F was used as an ignition temperature. These values were selected based on guidance in the EPRI FIVE document and are considered conservative based on a review of the actual cable types specified and installed at NMP2. The heat release rate for an electrical cabinet fire was assumed at 65 Btu/sec based on evaluation of electrical cabinet fires with qualified cable documented in tests conducted at Sandia National Laboratory (NUREG/CR-4527[33,34]). Heat release rate for non oil filled transformers was also taken at 65 Btu/sec since they are essentially windings of qualified cable. Similar to transformers, the heat release rate and worksheets for electric cabinets were used for screening fire ignition by electric motors. A significant variation in transient fire heat release rates can occur based on the types of transients. In most plant areas a trash fire as opposed to an oil fire is the appropriate transient fire consideration. The most severe transient trash fire in the FIVE report is a 32 gallon trash bag fire. However, the test that provided the heat release rate for the 32 gallon trash bag fire used binned yard waste (eucalyptus leaves). This is not considered representative of nuclear plant trash. For screening purposes, a transient fire heat release rate of 145 Btu/sec with total heat content of 130,500 Btu was selected based on a review of more representative transient fire tests. However, in the specific evaluation of detection and suppression system responses, the EPRI 32 gallon trash bag was used for analysis purposes.

The appropriate heat release rate was used repetitively in FIVE worksheet 1 for various target heights above fire source until the critical temperature rise at the target was equal to the damage temperature of 700°F or the ignition temperature of 932°F. The process was repeated for fire location factors for corner, wall, and center. Similarly radiation distances were evaluated using worksheet 3.

The information obtained in the preliminary evaluations is summarized in the following table of critical heights for damage and ignition. Also, the heat release rate (HRR) in BTU/sec and total heat released in BTUs is provided for each source.

Pre-Calculated Critical Heights (feet) for Damage and Ignition

SOURCE	USER		DAMAGE				IGNITION		
			Plume			Rad.	Plume		
	HRR	Btu	Center	Wall	Corner		Center	Wall	Corner
electrical cabinets	65	58500	3.8	5.0	6.6	1.4	3.1	4.1	5.4
transformers	65	58500	3.8	5.0	6.6	1.4	3.1	4.1	5.4
7 1/2 HP motors	65	10000	3.8	5.0	6.6	1.4	3.1	4.1	5.4
25 HP motors	65	32500	3.8	5.0	6.6	1.4	3.1	4.1	5.4
transients	145	130500	5.3	6.9	9.1	2.2	4.3	5.7	7.5

The above table was important in the detailed analysis of those areas that did not screen out during the initial conservative screening analysis. Inspecting (walkdown) the area for the dominant fire ignition sources (fire frequency contributors) and identifying cables or equipment within the critical distances above was an important strategy utilized in the evaluation of these areas. For example, the impact of damage to cables within the critical distance plus the impact of the source itself on the IPE model was considered. This impact in combination with the frequency of ignition usually allowed screening of areas without any further analysis. This significantly limited the number of fire modeling evaluations.

The following summarizes additional fire modeling analyses performed in support of the detailed fire analysis in Section 4.6.2:

- Corridor El 261 Control Building (FA88 331NW): whether automatic cable tray detection and water suppression successfully suppresses a fire before cable critical temperatures are reached was modeled. This was an important area from the initial screening analysis. The insights from this analysis were used to make judgments in other areas where there was automatic cable tray water sprays.

- Division II Standby Switchgear Room (FA19 336XL): whether the automatic detection and total flooding carbon dioxide system detects and suppresses a fire before cable critical temperatures are reached was modeled. The insights from this analysis were used to make judgments in other areas where there was automatic total flooding carbon dioxide system suppression.

- Service Water Pump Areas (FA60 807NZ and FA61 806NZ): whether an oil fire associated with one service water pump could potentially impact another pump nearby was considered.

Each of the above are further described below.

Division II Standby Switchgear Room (FA19 336XL)
Walkdown of the room identified a potential scenario location where an overhead cable tray (2TX565N) is located approximately 115 inches above the floor. Electrical panel 2BYS*SWG002B(-Y) is located under the cable tray and provides a wall location. The distance meets the transient screening criteria outlined above but provides an appropriate location where analysis can provide some insight to detection and suppression system interaction.

For analysis, an EPRI 32 gallon trash bag is used with a heat release rate of 380 Btu/s and total heat input of 114,000 Btu. For this scenario, involvement of tray 2TX565N is the target of interest. Important circuits are in trays above 2TX565N. Thus, the scenario represented is a potential intervening combustible involving cables. The pertinent dimensions in this case are ceiling height of 26' 7 1/2", cable tray 115" from floor, and total floor area of 2,470 square feet. Total flooding carbon dioxide is provided for the room with activation by ionization smoke detectors located at the ceiling. The first stage in the modeling was to use FIVE worksheet 1 (Scenario 336-1, 700°F damage threshold) to evaluate damage potential. As shown in Table 4.3-1, this indicated that the plume temperature would exceed critical temperature rise and potential damage. The next step was to use FIVE worksheet 1 to determine the temperature rise at the detectors (see table 4.3-2). This information was used with FIVE worksheet A-1 (see Table 4.3-3) to estimate time to damage and time to detection. The final step was to again use FIVE worksheet 1 with a damage temperature of 932°F to evaluate ignition potential (see Table 4.3-4).

Estimated temperature rise to cable tray 2TX565N from the specified transient trash bag will exceed the damage temperature of 700°F. Estimated time to damage is 400 seconds. Estimated time to detection is 4 seconds. The estimated time of achieving design suppression system concentration (after pre discharge alarm and discharge) is 94 seconds. Without suppression, the fire duration is 300 seconds. If allowed to go unsuppressed, the ignition temperature for 2TX565N (932°F) will not be obtained. Therefore, this scenario indicates that potential damage to 2TX565N could result, but that important circuits would not be damaged by the fire and no influence on core damage potential would result. Therefore, this scenario allows the potential fire threat to be dismissed without performing additional analysis or considering the limitations of the FIVE modeling methodology.

An additional scenario was identified for this area involving the top most breaker cubicle in panel 2BYS*SWG002B(-Y) which is approximately 30 inches below cable tray 2TX565N. For this evaluation, a heat release rate of 65 Btu/s was assumed (comparable with electrical panel). The FIVE modeling methodology indicates that cable damage in tray 2TX565N would occur approximately 37 seconds after start of event (Table 4.3-5, 6 and 7). Detection of the fire is estimated to occur approximately 45 seconds (Table 4.3-7) after start of event which indicates suppression concentration achievement approximately 135 seconds into the event. Ignition of cables in 2TX565N is estimated to occur approximately 80 seconds into the event (Table 4.3-8 and 9). Thus, it is likely that this scenario would result in some cable tray involvement. It is possible that 2TX564N, the next tray above 2TX565N, could be affected and impact RBCLC, however, this is unlikely and the scenario screens without suppression anyway. Since critical circuits (normal AC power) are several trays above TX565N, it is likely that suppression would occur prior to their involvement. The FIVE modeling methodology is appropriate for screening purposes only and is not capable of evaluating scenarios involving intervening combustibles and modeling fire growth. Based on the time to involvement of the first tray, this scenario is judged as not likely to result in any adverse impact to the critical circuits.

Control Building Corridor, Elevation 261' (FA88 331NW)
The walk down of this area did not reveal any significant area of concern. A parallel investigation by the IPEEE team revealed that one end of the corridor contained offsite power, balance of plant, and HPCS circuits. In addition, the screening analysis for this portion of corridor indicated that the area would screen out if automatic detection and suppression prevented circuit damage in the cable trays. Therefore, it was determined desirable to evaluate the detection and suppression system response to any potential fire. In order to do so, an EPRI 32 gallon trash bag transient was assumed.

For this scenario, only the volume of an isolated corridor section is utilized based on the constricted geometry of the corridor. This adds additional conservatism over using total compartment volume offered by the FIVE methodology but is considered appropriate based on the ability of a corridor to constrict fire plume effects. Basic scenario assumptions are as follows:

Ceiling is 26'-7 1/12" above floor
Target is 1st cable tray located 12'-2 1/2" above floor
Sprinkler is 1'-0" above tray
Detector is located 24'-0" above floor
Fire is assumed against wall
Targets are assumed in the fire plume

This scenario and dimensions are based upon compartment geometry and walk down measurements noted.

Worksheet 1 (Tables 4.3-10, 11 and 12) was used to evaluate the critical plume temperature rise at the target, the sprinkler head, and the detector. Worksheet A1 was then used to evaluate time to target damage, time to detection (Table 4.3-13), and then time to suppression (sprinkler actuation, Table 4.3-14).

The results of this scenario is that transient fire offers sufficient fuel and heat release rate to exceed the damage temperature of 700°F. Starting from time zero, fire detection is calculated to occur at 3.5 seconds, and fire suppression is calculated to occur at 43.92 seconds, while fire damage is calculated to occur at 432 seconds. Since suppression would occur long before damage, the transient fire source would not result in any damage to overhead electrical circuits.

Service Water Pump Room A (FA 61, Zone 806NZ)
Due to their importance to plant operation, during walk down of the service water pump rooms, it was determined desirable to evaluate the impact of an oil fire in the catch basin of one of the service water pumps.

Review of pertinent design drawings and walk down of the two rooms, indicated that Pump room A was more appropriate for evaluation since it is of lower compartment volume. The compartment volume for pump room A is 81,719 cubic feet. The catch basin for one of the service water pumps is 56.9 square feet. The closest pump to pump dimension is 99 inches. Pumps 1B and 1C are clear overhead to the ceiling (54 feet). Pump 1A has a unit cooler located approximately 7 feet overhead and 3 feet offset from the pump. Exposed cables in the area are greater than 15 feet from the closest pump. The postulated fire is based on 3 quarts of bearing oil (total capacity in one pump) or 5.7 lbm at 19,000 Btu/lbm. -

Based on the available spill area, the heat release rate for this fire is 7680 Btu/sec but due to fuel availability the fire is of short duration (less than 15 seconds). FIVE worksheet 1 (Table 4.3-15) indicates that damage threshold in the compartment would not be obtained at the ceiling (detector target). Worksheet A-1 (Table 4.3-16) indicates that if sufficient fuel were available, ceiling level damage would occur at 3600 seconds while detection would be within 3 seconds. This would allow ample time for fire brigade response to the area. FIVE worksheet 3 (Table 4.3-17) indicates that critical separation distance would be just over 15 1/2 feet. In addition, Worksheet 1 (Table 4.3-18) for exposure of the unit cooler to a fire in the basin for Pump 1A, indicates that damage threshold would be exceeded. However, due to the massive thermal reservoir represented by the structure and piping filled with cold water, it is not felt that in reality that any damage other than minor paint pealing would be created by such a short duration fire. That is, the modeling offered by FIVE is not sensitive enough to realistically model this scenario.

Table 4.3-1 Cable Tray 2TX565N Target (Transient Source)

FIRE AREA: 19 SCENARIO NO: 336-1

FIRE ZONE: 336XL

FIRE COMPARTMENT: Control Building Division II Standby Switchgear Room, El. 261'-0"

WORKSHEET 1: TARGET-IN-PLUME SCENARIO ENGLISH UNITS VERSION			
1	TARGET DAMAGE THRESHOLD TEMPERATURE (USE TABLE 1E FOR GUIDANCE)	700	F
2	HEIGHT OF TARGET ABOVE FIRE SOURCE (BASED ON SCENARIO GEOMETRY)	9.58	ft
3	HEIGHT FROM FIRE SOURCE TO CEILING (BASED ON SCENARIO GEOMETRY)	26.63	ft
4	PEAK FIRE INTENSITY (USE TABLE 2E & FIGURES 4-5 FOR GUIDANCE)	380	Btu/s
5	FIRE LOCATION FACTOR (4 FOR CORNER, 2 FOR WALL, 1 FOR CENTER)	2	--
6	EFFECTIVE HEAT RELEASE RATE ([BOX4] X [BOX5])	760	Btu/s
7	PLUME TEMPERATURE RISE AT TARGET (LOOK UP VALUE FROM TABLE 5E)	654.88	F
8	CRITICAL TEMPERATURE RISE AT TARGET ([BOX 1] - MAXIMUM AMBIANT TEMPERATURE)	596	F
9	CRITICAL PLUME TEMPERATURE RISE ([BOX 8] - [BOX 7])	-58.88	F
	IF THE ENTRY IN BOX 9 IS <=0, STOP. OTHERWISE, CONTINUE TO CALCULATE THE CRITICAL COMBUSTIBLE LOAD NEEDED TO RAISE THE AVERAGE TEMPERATURE BY THIS AMOUNT		
10	Qnet/V TO ACHIEVE TEMP RISE IN BOX 9 (LOOK UP VALUE FROM TABLE 7E)		Btu/ft3
11	CALCULATED ENCLOSURE VOLUME, V ([BOX 3] X FLOOR AREA OF SPACE)		ft3
12	CALCULATED CRITICAL Qnet ([BOX 10] X [BOX11])		Btu
13	ESTIMATED HEAT LOSS FRACTION (REPRESENTATIVE VALUE: 0.7)		--
14	ESTIMATE OF CRITICAL Qtot ([BOX 12] X [BOX 13])		Btu
15	ESTIMATE OF ACTUAL Qtot		Btu
	IF THE ENTRY IN BOX 15 IS LESS THAN THE VALUE IN BOX 14, CRITICAL CONDITIONS ARE NOT INDICATED FOR THE SCENARIO BEING EVALUATED. OTHERWISE, THE SCENARIO DOES NOT PASS THE SCREENING PROCEDURE. FURTHER ANALYSIS IS REQUIRED		

Table 4.3-2 Detector Target (Transient Source)

FIRE AREA: 19 SCENARIO NO: 336-1

FIRE ZONE: 336XL

FIRE COMPARTMENT: Control Building Division II Standby Switchgear Room, El. 261'-0"

WORKSHEET 1: TARGET-IN-PLUME SCENARIO ENGLISH UNITS VERSION			
1	TARGET DAMAGE THRESHOLD TEMPERATURE (USE TABLE 1E FOR GUIDANCE)	700	F
2	HEIGHT OF TARGET ABOVE FIRE SOURCE (BASED ON SCENARIO GEOMETRY)	26.63	ft
3	HEIGHT FROM FIRE SOURCE TO CEILING (BASED ON SCENARIO GEOMETRY)	26.63	ft
4	PEAK FIRE INTENSITY (USE TABLE 2E & FIGURES 4-5 FOR GUIDANCE)	380	Btu/s
5	FIRE LOCATION FACTOR (4 FOR CORNER, 2 FOR WALL, 1 FOR CENTER)	2	--
6	EFFECTIVE HEAT RELEASE RATE ([BOX4] X [BOX5])	760	Btu/s
7	PLUME TEMPERATURE RISE AT TARGET (LOOK UP VALUE FROM TABLE 5E)	119.27	F
8	CRITICAL TEMPERATURE RISE AT TARGET ([BOX 1] - MAXIMUM AMBIANT TEMPERATURE)	596	F
9	CRITICAL PLUME TEMPERATURE RISE ([BOX 8] - [BOX 7])	476.73	F
IF THE ENTRY IN BOX 9 IS <=0, STOP. OTHERWISE, CONTINUE TO CALCULATE THE CRITICAL COMBUSTIBLE LOAD NEEDED TO RAISE THE AVERAGE TEMPERATURE BY THIS AMOUNT			
10	Qnet/V TO ACHIEVE TEMP RISE IN BOX 9 (LOOK UP VALUE FROM TABLE 7E)		Btu/ft3
11	CALCULATED ENCLOSURE VOLUME, V ([BOX 3] X FLOOR AREA OF SPACE)		ft3
12	CALCULATED CRITICAL Qnet ([BOX 10] X [BOX11])		Btu
13	ESTIMATED HEAT LOSS FRACTION (REPRESENTATIVE VALUE: 0.7)		--
14	ESTIMATE OF CRITICAL Qtot ([BOX 12] X [BOX 13])		Btu
15	ESTIMATE OF ACTUAL Qtot		Btu
IF THE ENTRY IN BOX 15 IS LESS THAN THE VALUE IN BOX 14, CRITICAL CONDITIONS ARE NOT INDICATED FOR THE SCENARIO BEING EVALUATED. OTHERWISE, THE SCENARIO DOES NOT PASS THE SCREENING PROCEDURE. FURTHER ANALYSIS IS REQUIRED.			

Table 4.3-3 Time to Damage and Time to Detection (Cable Tray/Transient Source)

FIRE AREA: 19

FIRE ZONE: 336XL

FIRE COMPARTMENT: Control Building Division II Switchgear, El. 261'-0"

SCENARIO: 336-1

WORKSHEET A-1: TRANSIENT ANALYSIS THERMALLY THICK TARGETS ENGLISH UNITS VERSION			
1	Radiative heat flux at target (TABLE A-3E)	0.25	Btu/s/ft2
2	Convective heat flux at target (TABLES A-4E & A-5E)	1	Btu/s/ft2
3	Total heat flux at target ([BOX 1] + [BOX 2])	1.25	Btu/s/ft2
4	Target thermal response parameter (TABLE A-7E)	34	--
5	ESTIMATED TIME TO TARGET DAMAGE (TABLE A-2E)	400	s
6	Detection device rated temperature rise (MANUFACTURER'S DATA)	38	F
7	Gas Temperature rise at detector (USE BASIC SCREENING METHODOLOGY)	119.27	F
8	Detector temp rise/Gas temp rise ([BOX 6] / [BOX 7])	0.32	--
9	Deminsionless detector actuation time (TABLE A-1E)	0.4	--
10	Time constant of detection device (TABLE A-6E OR MFG. DATA)	10	s
11	ESTIMATED TIME TO DETECTOR ACTUATION ([BOX 9] X [BOX 10])	4	s

Table 4.3-4 Ignition Potential at Cable Tray 2TX565N (Transient Source)

FIRE AREA: 19 SCENARIO NO: 336-1

FIRE ZONE: 336XL

FIRE COMPARTMENT: Control Building Division II Standby Switchgear Room, El. 261'-0"

WORKSHEET 1: TARGET-IN-PLUME SCENARIO
ENGLISH UNITS VERSION

1	TARGET DAMAGE THRESHOLD TEMPERATURE (USE TABLE 1E FOR GUIDANCE)	932	F
2	HEIGHT OF TARGET ABOVE FIRE SOURCE (BASED ON SCENARIO GEOMETRY)	9.58	ft
3	HEIGHT FROM FIRE SOURCE TO CEILING (BASED ON SCENARIO GEOMETRY)	26.63	ft
4	PEAK FIRE INTENSITY (USE TABLE 2E & FIGURES 4-5 FOR GUIDANCE)	380	Btu/s
5	FIRE LOCATION FACTOR (4 FOR CORNER, 2 FOR WALL, 1 FOR CENTER)	2	--
6	EFFECTIVE HEAT RELEASE RATE ([BOX4] X [BOX5])	760	Btu/s
7	PLUME TEMPERATURE RISE AT TARGET (LOOK UP VALUE FROM TABLE 5E)	654.88	F
8	CRITICAL TEMPERATURE RISE AT TARGET ([BOX 1] - MAXIMUM AMBIANT TEMPERATURE)	828	F
9	CRITICAL PLUME TEMPERATURE RISE ([BOX.8] - [BOX 7])	173.12	F
	IF THE ENTRY IN BOX 9 IS <=0, STOP. OTHERWISE, CONTINUE TO CALCULATE THE CRITICAL COMBUSTIBLE LOAD NEEDED TO RAISE THE AVERAGE TEMPERATURE BY THIS AMOUNT		
10	Qnet/V TO ACHIEVE TEMP RISE IN BOX 9 (LOOK UP VALUE FROM TABLE 7E)	2.6	Btu/ft3
11	CALCULATED ENCLOSURE VOLUME, V ([BOX 3] X FLOOR AREA OF SPACE)	65,764	ft3
12	CALCULATED CRITICAL Qnet ([BOX 10] X [BOX11])	170,986	Btu
13	ESTIMATED HEAT LOSS FRACTION (REPRESENTATIVE VALUE: 0.7)	0.7	--
14	ESTIMATE OF CRITICAL Qtot ([BOX 12] X [BOX 13])	119,690	Btu
15	ESTIMATE OF ACTUAL Qtot	114,000	Btu

IF THE ENTRY IN BOX 15 IS LESS THAN THE VALUE IN BOX 14, CRITICAL CONDITIONS ARE NOT INDICATED FOR THE SCENARIO BEING EVALUATED. OTHERWISE, THE SCENARIO DOES NOT PASS THE SCREENING PROCEDURE. FURTHER ANALYSIS IS REQUIRED.

Table 4.3-5 Cable Tray 2TX565N Target (Cabinet Cubicle Source)

FIRE AREA: 19 SCENARIO NO: 336-2

FIRE ZONE: 336XL

FIRE COMPARTMENT: Control Building Division II Standby Switchgear Room, El. 261'-0"

WORKSHEET 1: TARGET-IN-PLUME SCENARIO ENGLISH UNITS VERSION			
1	TARGET DAMAGE THRESHOLD TEMPERATURE (USE TABLE 1E FOR GUIDANCE)	700	F
2	HEIGHT OF TARGET ABOVE FIRE SOURCE (BASED ON SCENARIO GEOMETRY)	2.50	ft
3	HEIGHT FROM FIRE SOURCE TO CEILING (BASED ON SCENARIO GEOMETRY)	19.54	ft
4	PEAK FIRE INTENSITY (USE TABLE 2E & FIGURES 4-5 FOR GUIDANCE)	65	Btu/s
5	FIRE LOCATION FACTOR (4 FOR CORNER, 2 FOR WALL, 1 FOR CENTER)	1	--
6	EFFECTIVE HEAT RELEASE RATE ([BOX4] X [BOX5])	65	Btu/s
7	PLUME TEMPERATURE RISE AT TARGET (LOOK UP VALUE FROM TABLE 5E)	1,193	F
8	CRITICAL TEMPERATURE RISE AT TARGET ([BOX 1] - MAXIMUM AMBIANT TEMPERATURE)	596	F
9	CRITICAL PLUME TEMPERATURE RISE ([BOX 8] - [BOX 7])	-597	F
IF THE ENTRY IN BOX 9 IS <=0, STOP. OTHERWISE, CONTINUE TO CALCULATE THE CRITICAL COMBUSTIBLE LOAD NEEDED TO RAISE THE AVERAGE TEMPERATURE BY THIS AMOUNT			
10	Qnet/V TO ACHIEVE TEMP RISE IN BOX 9 (LOOK UP VALUE FROM TABLE 7E)		Btu/ft3
11	CALCULATED ENCLOSURE VOLUME, V ([BOX 3] X FLOOR AREA OF SPACE)		ft3
12	CALCULATED CRITICAL Qnet ([BOX 10] X [BOX11])		Btu
13	ESTIMATED HEAT LOSS FRACTION (REPRESENTATIVE VALUE: 0.7)		--
14	ESTIMATE OF CRITICAL Qtot ([BOX 12] X [BOX 13])		Btu
15	ESTIMATE OF ACTUAL Qtot		Btu
IF THE ENTRY IN BOX 15 IS LESS THAN THE VALUE IN BOX 14, CRITICAL CONDITIONS ARE NOT INDICATED FOR THE SCENARIO BEING EVALUATED. OTHERWISE, THE SCENARIO DOES NOT PASS THE SCREENING PROCEDURE. FURTHER ANALYSIS IS REQUIRED.			

Table 4.3-6 Detector Target (Cabinet Cubicle Source)

FIRE AREA: 19 SCENARIO NO: 336-2

FIRE ZONE: 336XL

FIRE COMPARTMENT: Control Building Division II Standby Switchgear Room, El. 261'-0"

WORKSHEET 1: TARGET-IN-PLUME SCENARIO ENGLISH UNITS VERSION			
1	TARGET DAMAGE THRESHOLD TEMPERATURE (USE TABLE 1E FOR GUIDANCE)	700	F
2	HEIGHT OF TARGET ABOVE FIRE SOURCE (BASED ON SCENARIO GEOMETRY)	19.54	ft
3	HEIGHT FROM FIRE SOURCE TO CEILING (BASED ON SCENARIO GEOMETRY)	19.54	ft
4	PEAK FIRE INTENSITY (USE TABLE 2E & FIGURES 4-5 FOR GUIDANCE)	65	Btu/s
5	FIRE LOCATION FACTOR (4 FOR CORNER, 2 FOR WALL, 1 FOR CENTER)	1	--
6	EFFECTIVE HEAT RELEASE RATE ([BOX4] X [BOX5])	65	Btu/s
7	PLUME TEMPERATURE RISE AT TARGET (LOOK UP VALUE FROM TABLE 5E)	38.77	F
8	CRITICAL TEMPERATURE RISE AT TARGET ([BOX 1] - MAXIMUM AMBIANT TEMPERATURE)	596	F
9	CRITICAL PLUME TEMPERATURE RISE ([BOX 8] - [BOX 7])	457.23	F
IF THE ENTRY IN BOX 9 IS <=0, STOP. OTHERWISE, CONTINUE TO CALCULATE THE CRITICAL COMBUSTIBLE LOAD NEEDED TO RAISE THE AVERAGE TEMPERATURE BY THIS AMOUNT			
10	Qnet/V TO ACHIEVE TEMP RISE IN BOX 9 (LOOK UP VALUE FROM TABLE 7E)		Btu/ft3
11	CALCULATED ENCLOSURE VOLUME, V ([BOX 3] X FLOOR AREA OF SPACE)		ft3
12	CALCULATED CRITICAL Qnet ([BOX 10] X [BOX11])		Btu
13	ESTIMATED HEAT LOSS FRACTION (REPRESENTATIVE VALUE: 0.7)		--
14	ESTIMATE OF CRITICAL Qtot ([BOX 12] X [BOX 13])		Btu
15	ESTIMATE OF ACTUAL Qtot		Btu
IF THE ENTRY IN BOX 15 IS LESS THAN THE VALUE IN BOX 14, CRITICAL CONDITIONS ARE NOT INDICATED FOR THE SCENARIO BEING EVALUATED. OTHERWISE, THE SCENARIO DOES NOT PASS THE SCREENING PROCEDURE. FURTHER ANALYSIS IS REQUIRED.			

Table 4.3-7 Time to Damage in 2TX265N and to Detection (Cabinet Cubicle Source)

FIRE AREA: 19

FIRE ZONE: 336XL

FIRE COMPARTMENT: Control Building Division II
Switchgear Room, El. 261'-0"

SCENARIO: 336-2

WORKSHEET A-1: TRANSIENT ANALYSIS THERMALLY THICK TARGETS ENGLISH UNITS VERSION			
1	Radiative heat flux at target (TABLE A-3E)	1.2	Btu/s/ft2
2	Convective heat flux at target (TABLES A-4E & A-5E)	4.8	Btu/s/ft2
3	Total heat flux at target ([BOX 1] + [BOX 2])	6	Btu/s/ft2
4	Target thermal response parameter (TABLE A-7E)	34	--
5	ESTIMATED TIME TO TARGET DAMAGE (TABLE A-2E)	37	s
6	Detection device rated temperature rise (MANUFACTURER'S DATA)	38	F
7	Gas Temperature rise at detector (USE BASIC SCREENING METHODOLOGY)	38.77	F
8	Detector temp rise/Gas temp rise ([BOX 6] / [BOX 7])	0.98	--
9	Deminsionless detector actuation time (TABLE A-1E)	4.5	--
10	Time constant of detection device (TABLE A-6E OR MFG. DATA)	10	s
11	ESTIMATED TIME TO DETECTOR ACTUATION ([BOX 9] X [BOX 10])	45	s

Table 4.3-8 2TX265N Target - Ignition (Cabinet Cubicle Source)

FIRE AREA: 19 SCENARIO NO: 336-2

FIRE ZONE: 336XL

FIRE COMPARTMENT: Control Building Division II Standby Switchgear Room, El. 261'-0"

WORKSHEET 1: TARGET-IN-PLUME SCENARIO ENGLISH UNITS VERSION			
1	TARGET DAMAGE THRESHOLD TEMPERATURE (USE TABLE 1E FOR GUIDANCE)	932	F
2	HEIGHT OF TARGET ABOVE FIRE SOURCE (BASED ON SCENARIO GEOMETRY)	2.50	ft
3	HEIGHT FROM FIRE SOURCE TO CEILING (BASED ON SCENARIO GEOMETRY)	19.54	ft
4	PEAK FIRE INTENSITY (USE TABLE 2E & FIGURES 4-5 FOR GUIDANCE)	65	Btu/s
5	FIRE LOCATION FACTOR (4 FOR CORNER, 2 FOR WALL, 1 FOR CENTER)	1	--
6	EFFECTIVE HEAT RELEASE RATE ([BOX4] X [BOX5])	65	Btu/s
7	PLUME TEMPERATURE RISE AT TARGET (LOOK UP VALUE FROM TABLE 5E)	1,193	F
8	CRITICAL TEMPERATURE RISE AT TARGET ([BOX 1] - MAXIMUM AMBIANT TEMPERATURE)	828	F
9	CRITICAL PLUME TEMPERATURE RISE ([BOX 8] - [BOX 7])	-365.59	F
IF THE ENTRY IN BOX 9 IS <=0, STOP. OTHERWISE, CONTINUE TO CALCULATE THE CRITICAL COMBUSTIBLE LOAD NEEDED TO RAISE THE AVERAGE TEMPERATURE BY THIS AMOUNT			
10	Qnet/V TO ACHIEVE TEMP RISE IN BOX 9 (LOOK UP VALUE FROM TABLE 7E)		Btu/ft3
11	CALCULATED ENCLOSURE VOLUME, V ([BOX 3] X FLOOR AREA OF SPACE)		ft3
12	CALCULATED CRITICAL Qnet ([BOX 10] X [BOX11])		Btu
13	ESTIMATED HEAT LOSS FRACTION (REPRESENTATIVE VALUE: 0.7)		--
14	ESTIMATE OF CRITICAL Qtot ([BOX 12] X [BOX 13])		Btu
15	ESTIMATE OF ACTUAL Qtot		Btu
IF THE ENTRY IN BOX 15 IS LESS THAN THE VALUE IN BOX 14, CRITICAL CONDITIONS ARE NOT INDICATED FOR THE SCENARIO BEING EVALUATED. OTHERWISE, THE SCENARIO DOES NOT PASS THE SCREENING PROCEDURE. FURTHER ANALYSIS IS REQUIRED			

Table 4.3-9 Time to Ignitiion - 2TX265N (Cabinet Cubicle Source)

FIRE AREA: 19

FIRE ZONE: 336XL

FIRE COMPARTMENT: Control Building Division II
Switchgear Room, El. 261'-0"

SCENARIO: 336-2

WORKSHEET A-1: TRANSIENT ANALYSIS THERMALLY THICK TARGETS ENGLISH UNITS VERSION			
1	Radiative heat flux at target (TABLE A-3E)	0.33	Btu/s/ft2
2	Convective heat flux at target (TABLES A-4E & A-5E)	3.12	Btu/s/ft2
3	Total heat flux at target ([BOX 1] + [BOX 2])	3.45	Btu/s/ft2
4	Target thermal response parameter (TABLE A-7E)	34	--
5	ESTIMATED TIME TO TARGET DAMAGE (TABLE A-2E)	80	s
6	Detection device rated temperature rise (MANUFACTURER'S DATA)		F
7	Gas Temperature rise at detector (USE BASIC SCREENING METHODOLOGY)		F
8	Detector temp rise/Gas temp rise ([BOX 6] / [BOX 7])		--
9	Deminsionless detector actuation time (TABLE A-1E)		--
10	Time constant of detection device (TABLE A-6E OR MFG. DATA)		s
11	ESTIMATED TIME TO DETECTOR ACTUATION ([BOX 9] X [BOX 10])		s

Table 4.3-10 Cable Tray Target (Transient Source)

FIRE AREA: 88 SCENARIO NO: 331-1

FIRE ZONE: 331NW

FIRE COMPARTMENT: Control Building Corridor, El. 261'-0"

WORKSHEET 1: TARGET-IN-PLUME SCENARIO ENGLISH UNITS VERSION			
1	TARGET DAMAGE THRESHOLD TEMPERATURE (USE TABLE 1E FOR GUIDANCE)	700	F
2	HEIGHT OF TARGET ABOVE FIRE SOURCE (BASED ON SCENARIO GEOMETRY)	12.21	ft
3	HEIGHT FROM FIRE SOURCE TO CEILING (BASED ON SCENARIO GEOMETRY)	26.63	ft
4	PEAK FIRE INTENSITY (USE TABLE 2E & FIGURES 4-5 FOR GUIDANCE)	380	Btu/s
5	FIRE LOCATION FACTOR (4 FOR CORNER, 2 FOR WALL, 1 FOR CENTER)	2	--
6	EFFECTIVE HEAT RELEASE RATE ([BOX4] X [BOX5])	760	Btu/s
7	PLUME TEMPERATURE RISE AT TARGET (LOOK UP VALUE FROM TABLE 5E)	437.45	F
8	CRITICAL TEMPERATURE RISE AT TARGET ([BOX 1] - MAXIMUM AMBIANT TEMPERATURE)	596	F
9	CRITICAL PLUME TEMPERATURE RISE ([BOX 8] - [BOX 7])	158.55	F
IF THE ENTRY IN BOX 9 IS <=0, STOP. OTHERWISE, CONTINUE TO CALCULATE THE CRITICAL COMBUSTIBLE LOAD NEEDED TO RAISE THE AVERAGE TEMPERATURE BY THIS AMOUNT			
10	Qnet/V TO ACHIEVE TEMP RISE IN BOX 9 (LOOK UP VALUE FROM TABLE 7E)	2.5	Btu/ft3
11	CALCULATED ENCLOSURE VOLUME, V ([BOX 3] X FLOOR AREA OF SPACE)	17,772	ft3
12	CALCULATED CRITICAL Qnet ([BOX 10] X [BOX11])	44,430	Btu
13	ESTIMATED HEAT LOSS FRACTION (REPRESENTATIVE VALUE: 0.7)	0.7	--
14	ESTIMATE OF CRITICAL Qtot ([BOX 12] X [BOX 13])	31,101	Btu
15	ESTIMATE OF ACTUAL Qtot	114,000	Btu
IF THE ENTRY IN BOX 15 IS LESS THAN THE VALUE IN BOX 14, CRITICAL CONDITIONS ARE NOT INDICATED FOR THE SCENARIO BEING EVALUATED. OTHERWISE, THE SCENARIO DOES NOT PASS THE SCREENING PROCEDURE. FURTHER ANALYSIS IS REQUIRED.			

Table 4.3-11 Sprinkler Heat Target (Transient Source)

FIRE AREA: 88 SCENARIO NO: 331-1

FIRE ZONE: 331NW

FIRE COMPARTMENT: Control Building Corridor, El. 261'-0"

WORKSHEET 1: TARGET-IN-PLUME SCENARIO
ENGLISH UNITS VERSION

1	TARGET DAMAGE THRESHOLD TEMPERATURE (USE TABLE 1E FOR GUIDANCE)	700	F
2	HEIGHT OF TARGET ABOVE FIRE SOURCE (BASED ON SCENARIO GEOMETRY)	13.21	ft
3	HEIGHT FROM FIRE SOURCE TO CEILING (BASED ON SCENARIO GEOMETRY)	26.63	ft
4	PEAK FIRE INTENSITY (USE TABLE 2E & FIGURES 4-5 FOR GUIDANCE)	380	Btu/s
5	FIRE LOCATION FACTOR (4 FOR CORNER, 2 FOR WALL, 1 FOR CENTER)	2	--
6	EFFECTIVE HEAT RELEASE RATE ([BOX4] X [BOX5])	760	Btu/s
7	PLUME TEMPERATURE RISE AT TARGET (LOOK UP VALUE FROM TABLE 5E)	383.57	F
8	CRITICAL TEMPERATURE RISE AT TARGET ([BOX 1] - MAXIMUM AMBIANT TEMPERATURE)	596	F
9	CRITICAL PLUME TEMPERATURE RISE ([BOX 8] - [BOX 7])	212.43	F
	IF THE ENTRY IN BOX 9 IS <=0, STOP. OTHERWISE, CONTINUE TO CALCULATE THE CRITICAL COMBUSTIBLE LOAD NEEDED TO RAISE THE AVERAGE TEMPERATURE BY THIS AMOUNT		
10	Qnet/V TO ACHIEVE TEMP RISE IN BOX 9 (LOOK UP VALUE FROM TABLE 7E)	3.25	Btu/ft3
11	CALCULATED ENCLOSURE VOLUME, V ([BOX 3] X FLOOR AREA OF SPACE)	17,772	ft3
12	CALCULATED CRITICAL Qnet ([BOX 10] X [BOX11])	57,759	Btu
13	ESTIMATED HEAT LOSS FRACTION (REPRESENTATIVE VALUE: 0.7)	0.7	--
14	ESTIMATE OF CRITICAL Qtot ([BOX 12] X [BOX 13])	40,431	Btu
15	ESTIMATE OF ACTUAL Qtot	114,000	Btu
	IF THE ENTRY IN BOX 15 IS LESS THAN THE VALUE IN BOX 14, CRITICAL CONDITIONS ARE NOT INDICATED FOR THE SCENARIO BEING EVALUATED. OTHERWISE, THE SCENARIO DOES NOT PASS THE SCREENING PROCEDURE. FURTHER ANALYSIS IS REQUIRED.		

Table 4.3-12 Smoke Detector Target (Transient Source)

FIRE AREA: 88 SCENARIO NO: 331-1

FIRE ZONE: 331NW

FIRE COMPARTMENT: Control Building Corridor, El. 261'-0"

WORKSHEET 1: TARGET-IN-PLUME SCENARIO ENGLISH UNITS VERSION			
1	TARGET DAMAGE THRESHOLD TEMPERATURE (USE TABLE 1E FOR GUIDANCE)	700	F
2	HEIGHT OF TARGET ABOVE FIRE SOURCE (BASED ON SCENARIO GEOMETRY)	24.00	ft
3	HEIGHT FROM FIRE SOURCE TO CEILING (BASED ON SCENARIO GEOMETRY)	26.63	ft
4	PEAK FIRE INTENSITY (USE TABLE 2E & FIGURES 4-5 FOR GUIDANCE)	380	Btu/s
5	FIRE LOCATION FACTOR (4 FOR CORNER, 2 FOR WALL, 1 FOR CENTER)	2	--
6	EFFECTIVE HEAT RELEASE RATE ([BOX4] X [BOX5])	760	Btu/s
7	PLUME TEMPERATURE RISE AT TARGET (LOOK UP VALUE FROM TABLE 5E)	141.80	F
8	CRITICAL TEMPERATURE RISE AT TARGET ([BOX 1] - MAXIMUM AMBIANT TEMPERATURE)	596	F
9	CRITICAL PLUME TEMPERATURE RISE ([BOX 8] - [BOX 7])	454.20	F
IF THE ENTRY IN BOX 9 IS <=0, STOP. OTHERWISE, CONTINUE TO CALCULATE THE CRITICAL COMBUSTIBLE LOAD NEEDED TO RAISE THE AVERAGE TEMPERATURE BY THIS AMOUNT			
10	Qnet/V TO ACHIEVE TEMP RISE IN BOX 9 (LOOK UP VALUE FROM TABLE 7E)	5.7	Btu/ft3
11	CALCULATED ENCLOSURE VOLUME, V ([BOX 3] X FLOOR AREA OF SPACE)	17,772	ft3
12	CALCULATED CRITICAL Qnet ([BOX 10] X [BOX11])	101,301	Btu
13	ESTIMATED HEAT LOSS FRACTION (REPRESENTATIVE VALUE: 0.7)	0.7	--
14	ESTIMATE OF CRITICAL Qtot ([BOX 12] X [BOX 13])	70,911	Btu
15	ESTIMATE OF ACTUAL Qtot	114,000	Btu
IF THE ENTRY IN BOX 15 IS LESS THAN THE VALUE IN BOX 14, CRITICAL CONDITIONS ARE NOT INDICATED FOR THE SCENARIO BEING EVALUATED. OTHERWISE, THE SCENARIO DOES NOT PASS THE SCREENING PROCEDURE. FURTHER ANALYSIS IS REQUIRED.			

Table 4.3-13 Time to Damage Cable Tray and Time to Detect (Transient Source)

FIRE AREA: 88

FIRE ZONE: 331NW

FIRE COMPARTMENT: Control Building Coridor
El. 261'-0"

SCENARIO: 331-1

WORKSHEET A-1: TRANSIENT ANALYSIS THERMALLY THICK TARGETS ENGLISH UNITS VERSION			
1	Radiative heat flux at target (TABLE A-3E)	0.1	Btu/s/ft2
2	Convective heat flux at target (TABLES A-4E & A-5E)	1.5	Btu/s/ft2
3	Total heat flux at target ([BOX 1] + [BOX 2])	1.6	Btu/s/ft2
4	Target thermal response parameter (TABLE A-7E)	34	--
5	ESTIMATED TIME TO TARGET DAMAGE (TABLE A-2E)	428	s
6	Detection device rated temperature rise (MANUFACTURER'S DATA)	38	F
7	Gas Temperature rise at detector (USE BASIC SCREENING METHODOLOGY)	141.80	F
8	Detector temp rise/Gas temp rise ([BOX 6] / [BOX 7])	0.27	--
9	Deminsionless detector actuation time (TABLE A-1E)	0.35	--
10	Time constant of detection device (TABLE A-6E OR MFG. DATA)	10	s
11	ESTIMATED TIME TO DETECTOR ACTUATION ([BOX 9] X [BOX 10])	3.5	s

Table 4.3-14 Time to Sprinkler Activation (Transient Source)

FIRE AREA: 88

FIRE ZONE: 331NW

FIRE COMPARTMENT: Control Building Coridor

El. 261'-0"

SCENARIO: 331-1

WORKSHEET A-1: TRANSIENT ANALYSIS THERMALLY THICK TARGETS ENGLISH UNITS VERSION			
1	Radiative heat flux at target (TABLE A-3E)	0.1	Btu/s/ft2
2	Convective heat flux at target (TABLES A-4E & A-5E)	1.5	Btu/s/ft2
3	Total heat flux at target ([BOX 1] + [BOX 2])	1.6	Btu/s/ft2
4	Target thermal response parameter (TABLE A-7E)	34	--
5	ESTIMATED TIME TO TARGET DAMAGE (TABLE A-2E)	428	s
6	Detection device rated temperature rise (MANUFACTURER'S DATA)	71	F
7	Gas Temperature rise at detector (USE BASIC SCREENING METHODOLOGY)	383.57	F
8	Detector temp rise/Gas temp rise ([BOX 6] / [BOX 7])	0.19	--
9	Deminsionless detector actuation time (TABLE A-1E)	0.183	--
10	Time constant of detection device (TABLE A-6E OR MFG. DATA)	240	s
11	ESTIMATED TIME TO DETECTOR ACTUATION ([BOX 9] X [BOX 10])	43.92	s

Table 4.3-15 Damage at Ceiling - Detector Target

FIRE AREA: 61 SCENARIO NO: 806-1

FIRE ZONE: 806NZ

FIRE COMPARTMENT: Service Water Pump Room A

WORKSHEET 1: TARGET-IN-PLUME SCENARIO ENGLISH UNITS VERSION			
1	TARGET DAMAGE THRESHOLD TEMPERATURE (USE TABLE 1E FOR GUIDANCE)	700	F
2	HEIGHT OF TARGET ABOVE FIRE SOURCE (BASED ON SCENARIO GEOMETRY)	55.00	ft
3	HEIGHT FROM FIRE SOURCE TO CEILING (BASED ON SCENARIO GEOMETRY)	57.00	ft
4	PEAK FIRE INTENSITY (USE TABLE 2E & FIGURES 4-5 FOR GUIDANCE)	7680	Btu/s
5	FIRE LOCATION FACTOR (4 FOR CORNER, 2 FOR WALL, 1 FOR CENTER)	1	--
6	EFFECTIVE HEAT RELEASE RATE ([BOX4] X [BOX5])	7680	Btu/s
7	PLUME TEMPERATURE RISE AT TARGET (LOOK UP VALUE FROM TABLE 5E)	166.39	F
8	CRITICAL TEMPERATURE RISE AT TARGET ([BOX 1] - MAXIMUM AMBIANT TEMPERATURE)	596	F
9	CRITICAL PLUME TEMPERATURE RISE ([BOX 8] - [BOX 7])	429.61	F
IF THE ENTRY IN BOX 9 IS <=0, STOP. OTHERWISE, CONTINUE TO CALCULATE THE CRITICAL COMBUSTIBLE LOAD NEEDED TO RAISE THE AVERAGE TEMPERATURE BY THIS AMOUNT			
10	Qnet/V TO ACHIEVE TEMP RISE IN BOX 9 (LOOK UP VALUE FROM TABLE 7E)	5.6	Btu/ft3
11	CALCULATED ENCLOSURE VOLUME, V ([BOX 3] X FLOOR AREA OF SPACE)	81,719	ft3
12	CALCULATED CRITICAL Qnet ([BOX 10] X [BOX11])	457,626	Btu
13	ESTIMATED HEAT LOSS FRACTION (REPRESENTATIVE VALUE: 0.7)	0.7	--
14	ESTIMATE OF CRITICAL Qtot ([BOX 12] X [BOX 13])	320,338	Btu
15	ESTIMATE OF ACTUAL Qtot	108,300	Btu
IF THE ENTRY IN BOX 15 IS LESS THAN THE VALUE IN BOX 14, CRITICAL CONDITIONS ARE NOT INDICATED FOR THE SCENARIO BEING EVALUATED. OTHERWISE, THE SCENARIO DOES NOT PASS THE SCREENING PROCEDURE. FURTHER ANALYSIS IS REQUIRED.			

Table 4.3-16 Time to Damage and Time to Detect

FIRE AREA: 61

FIRE ZONE: 806NZ

FIRE COMPARTMENT: Service Water Pump Room A, El 224, 261'

SCENARIO: 806-1

WORKSHEET A-1: TRANSIENT ANALYSIS THERMALLY THICK TARGETS ENGLISH UNITS VERSION			
1	Radiative heat flux at target (TABLE A-3E)	0.08	Btu/s/ft2
2	Convective heat flux at target (TABLES A-4E & A-5E)	0.43	Btu/s/ft2
3	Total heat flux at target ([BOX 1] + [BOX 2])	0.51	Btu/s/ft2
4	Target thermal response parameter (TABLE A-7E)	34	--
5	ESTIMATED TIME TO TARGET DAMAGE (TABLE A-2E)	3600	s
6	Detection device rated temperature rise (MANUFACTURER'S DATA)	38	F
7	Gas Temperature rise at detector (USE BASIC SCREENING METHODOLOGY)	166.39	F
8	Detector temp rise/Gas temp rise ([BOX 6] / [BOX 7])	0.23	--
9	Deminsionless detector actuation time (TABLE A-1E)	0.3	--
10	Time constant of detection device (TABLE A-6E OR MFG. DATA)	10	s
11	ESTIMATED TIME TO DETECTOR ACTUATION ([BOX 9] X [BOX 10])	3	s

Table 4.3-17 Radient Damage Distance

FIRE AREA: 61 SCENARIO NO: 806-1

FIRE ZONE: 806NZ

FIRE COMPARTMENT: Service Water Pump Room A

WORKSHEET 3: RADIATION EXPOSURE SCENARIOS ENGLISH UNITS VERSION

1	CRITICAL RADIANT FLUX TO TARGET (LOOK UP FROM TABLE 1E)	1	Btu/s/ft2
2	PEAK FIRE INTENSITY (USE TABLE 2E FOR GUIDANCE)	7680	Btu/s
3	RADIANT FRACTION OF HEAT RELEASE (REPRESENTATIVE VALUE = 0.4)	0.4	--
4	RADIANT HEAT RELEASE RATE ([BOX 2] X [BOX 3])	3072	Btu/s
5	CRITICAL RADIANT FLUX DISTANCE (LOOK UP VALUE FROM TABLE 10E)	15.64	ft
	IF THE EXPOSURE IS LOCATED WITHIN THIS DISTANCE (INDICATED IN BOX 5) OF THE TARGET, CRITICAL CONDITIONS CAN OCCUR. OUTSIDE THIS RANGE, CRITICAL CONDITIONS ARE NOT INDICATED FOR THE SCENARIO UNDER CONSIDERATION.		

Table 4.3-18 Unit Cooler Target

FIRE AREA: 61 SCENARIO NO: 806-1

FIRE ZONE: 806NZ

FIRE COMPARTMENT: Service Water Pump Room A

WORKSHEET 1: TARGET-IN-PLUME SCENARIO ENGLISH UNITS VERSION			
1	TARGET DAMAGE THRESHOLD TEMPERATURE (USE TABLE 1E FOR GUIDANCE)	700	F
2	HEIGHT OF TARGET ABOVE FIRE SOURCE (BASED ON SCENARIO GEOMETRY)	7.00	ft
3	HEIGHT FROM FIRE SOURCE TO CEILING (BASED ON SCENARIO GEOMETRY)	57.00	ft
4	PEAK FIRE INTENSITY (USE TABLE 2E & FIGURES 4-5 FOR GUIDANCE)	7680	Btu/s
5	FIRE LOCATION FACTOR (4 FOR CORNER, 2 FOR WALL, 1 FOR CENTER)	1	--
6	EFFECTIVE HEAT RELEASE RATE ([BOX4] X [BOX5])	7680	Btu/s
7	PLUME TEMPERATURE RISE AT TARGET (LOOK UP VALUE FROM TABLE 5E)	5,166	F
8	CRITICAL TEMPERATURE RISE AT TARGET ([BOX 1] - MAXIMUM AMBIANT TEMPERATURE)	596	F
9	CRITICAL PLUME TEMPERATURE RISE ([BOX 8] - [BOX 7])	-4,570	F
IF THE ENTRY IN BOX 9 IS <=0, STOP. OTHERWISE, CONTINUE TO CALCULATE THE CRITICAL COMBUSTIBLE LOAD NEEDED TO RAISE THE AVERAGE TEMPERATURE BY THIS AMOUNT			
10	Qnet/V TO ACHIEVE TEMP RISE IN BOX 9 (LOOK UP VALUE FROM TABLE 7E)		Btu/ft3
11	CALCULATED ENCLOSURE VOLUME, V ([BOX 3] X FLOOR AREA OF SPACE)		ft3
12	CALCULATED CRITICAL Qnet ([BOX 10] X [BOX11])		Btu
13	ESTIMATED HEAT LOSS FRACTION (REPRESENTATIVE VALUE: 0.7)		--
14	ESTIMATE OF CRITICAL Qtot ([BOX 12] X [BOX 13])		Btu
15	ESTIMATE OF ACTUAL Qtot		Btu
IF THE ENTRY IN BOX 15 IS LESS THAN THE VALUE IN BOX 14, CRITICAL CONDITIONS ARE NOT INDICATED FOR THE SCENARIO BEING EVALUATED. OTHERWISE, THE SCENARIO DOES NOT PASS THE SCREENING PROCEDURE. FURTHER ANALYSIS IS REQUIRED.			

4.4 Evaluation of Component Fragilities and Failure Modes

Components were assumed to either fail with a probability of 1.0 if the fire got close enough or they had a chance of success based on reliability and availability models in the IPE[1] (IPE also identifies failure modes). The following summarizes the treatment of component failures:

- In the initial screening analysis (Section 4.6.1), all equipment in the compartment being analyzed was assumed to fail. There was no credit taken for detection or suppression.

- In the detailed analysis (Section 4.6.2), equipment that are fire sources were assumed to fail and target equipment were assumed to fail if in the zone of influence (i.e., plume and hot gases). No explicit credit for manual suppression is used in the analysis. Some credit is taken for automatic detection and suppression as described in Sections 4.3 and 4.6.2.

4.5 Fire Detection and Suppression

Section 9.5.1 and Appendices 9A and 9B of the USAR[6] describe in detail the fire protection program including detection and suppression capabilities.

Fire detection is provided in each compartment evaluated in this analysis. Those areas requiring more detailed analysis in Section 4.6.2 (i.e., did not screen out as part of the initial screening analysis in Section 4.6.1) explicitly discuss detection and suppression capabilities as well as how these systems are credited in the analysis.

Many areas also have automatic suppression systems or manual suppression capabilities. Again, those areas requiring more detailed analysis in Section 4.6.2 (i.e., did not screen out as part of the initial screening analysis in Section 4.6.1) explicitly discuss detection and suppression capabilities as well as how these systems are credited in the analysis.

When explicit credit is taken for detection and suppression for screening compartments in the detailed analysis (Section 4.6.2), an unreliability of 0.05 per demand is used for automatic detection and suppression. A plant specific systems analysis to estimate reliability was not deemed necessary. No significant reliability problems have been observed at NMP2 and the 0.05 value bounds the recommended values from FIVE[25] without redundancy (Table 2 in FIVE Attachment 10.3). No explicit credit is taken for manual suppression of fires in the screening analysis calculations. This was an implicit consideration and is discussed above and in the Section 4.6, as appropriate. For these reasons, access to compartments was not explicitly considered or evaluated. However, those compartments most important to risk have at least two access paths.

Suppression induced damage due to flooding was considered in the design of the plant and fire protection systems (USAR[6]). This was also considered in the seismic analysis as described in Sections 3.1.2.1.5 and 4.8. The potential for a fire to cause damage to other equipment in the compartment due to suppression of the fire is a consideration for those areas where detailed analysis was performed. However, no such scenarios were identified during the analysis or walkdown. See Section 4.6.2 for a more detailed discussion.

The adequacy of fire fighting procedures, fire brigade training, and equipment is described in Section 4.8.

4.6 Analysis of Plant Systems, Sequences, and Plant Response

Section 4.6.1 summarizes the development of databases and the initial screening of fire compartments. The results are summarized in Table 4.0-1. Section 4.6.2 documents the detailed analysis of fire compartments that did not screen out of the initial screening analysis described in Section 4.6.1. The results are summarized in Section 4.0 and Table 4.0-2 as well as Section 4.6.2.

At NMP2, fires zones are detection zones and are a subset of fire areas. The fire zones evaluated in the initial screening analysis are synonymous with the definition of fire compartments in the FIVE methodology[25] with a few exceptions such as the reactor building. However, the reactor building required detailed analysis in this report anyway as described in Section 4.6.2.

4.6.1 Overview of Fire PRA (FPRA) Initial Screening[29]

This section summarizes the initial screening of NMP2 fire zones in support of the IPEEE, FIVE evaluation[29]. The results of this initial screening evaluation are in Table 4.0-1. The first four columns of the table list the fire areas, fire zones, fire area/zone description, and the annual fire frequency for the fire zone based on the evaluation described in Section 4.1. The "App R" column lists the safety Division (I or II) associated with the zone, as shown in the Appendix R analysis. A "N" indicates that nonsafety related equipment and cables are in this zone. The "Initiator" and "Screening Summary" columns summarize the results of the screening evaluation. Although there may be more than one initiator based on the impact identified in the table, usually the initiator with the most significant impact is assumed (i.e., loss of emergency bus versus MSIV closure). Core damage frequency estimates were developed using the IPE model to quantify fire initiators. The remaining columns of Table 4.0-1 summarize the impact on IPE systems (event tree top events) assuming that everything in the fire zone fails. Where control circuits could possibly cause failure, they are assumed to occur. The notes to Table 4.0-1 explain the columns and codes used to summarize impacts. Those fire zones that did not screen out of this initial conservative screening analysis are evaluated in greater detail in Section 4.6.2.

Initially very few areas were screened in the FIVE evaluation[27] because the reliability of safe shutdown equipment identified for Appendix R was not sufficiently reliable without the knowledge of where non Appendix R equipment (i.e., cables) is located. Thus, there was a need to identify additional success paths (i.e., offsite power, main feedwater, main condenser, and their support systems) to more realistically screen fire areas. In addition, it was recognized at the beginning of the FIVE evaluation that screening areas that do not contain Appendix R equipment may not be justified from a risk perspective without some additional evaluation. These two situation resulted in the decision to utilize a probabilistic risk assessment approach in concert with the FIVE evaluation.

The following summarizes the basic approach used in this analysis to screen fire areas:

- A computerized spatial database was developed such that all plant cables and components in a fire zone can be identified[28].

- Location dependencies were identified for the offsite power supplies, main feedwater, main condenser, and their support systems[29]. This provides additional success paths and results in improved plant reliability for screening a number of areas. The IPE[1] was used to identify the systems and dependencies necessary to support these key functions. Then, cable block diagrams were developed, identifying critical cables[29]. With the cables and their impact on the IPE identified, the spatial database[28] was queried to determined the fire zones where these critical cables are located.

- The spatial database[28], Appendix R database[6], and location dependencies[29] for non Appendix R equipment were used to identify component and system impacts given a fire in the zone. Initially, the fire is assumed to fail all cables and components in the zone. Fire impact includes consideration of initiating events (plant trip or immediate shutdown) and unavailability of systems modeled in the IPE.

- Based on the impact and frequency of a fire in the area, a screening process is used to determine whether a fire in the area represents an insignificant contribution to public safety or whether additional more detailed analysis should be considered. The frequency of a fire in the area is based on the FIVE evaluation described in Section 4.1. The IPE is used to support both qualitative screening judgments and quantitative screening.

Several screening techniques were utilized in this evaluation as summarized below:

- Quantitative screening using the IPE was performed for several fire zones. An initiating event fire for a specific fire zone was defined and event tree rules were revised to account for the fire impact. If annual core damage frequency is less than 1E-6, the zone is considered to be screened out.

  This screening criteria is considered reasonable because the impact of a fire is conservatively assumed to fail everything in the zone. Typical reduction factors (i.e., geometric and severity factors within an area given a fire in the area) in fire PRAs are on the order of 0.1 or less. Thus, annual core damage frequency should be on the order of 1E-7 or less which is less than 1% of the IPE core damage frequency.

- If a fire does not cause an initiating event, the unavailability of systems in the fire zone, based on the fire frequency, are compared to the IPE. In general, the unavailability from a fire (e.g., frequency of a fire taken over a 24 hour mission time) is small in comparison to unavailabilities from the IPE. In cases where there is significant damage to safety related equipment, an initiating event is assumed in this initial screening analysis.

- Qualitative screening was used when no initiating event or significant impact on IPE systems could be identified - it is obvious that risk quantification would result in values less than 1E-7/yr.

4.6.1.1 Identification of Non-Appendix R Critical Cables[29]

This section summarizes the identification of critical cables and their locations for a number of systems such as offsite power, main feedwater, main condenser, and their support systems. With this information, more realistic impacts of fires can be assessed and quantified with the IPE to screen fire areas. The following systems, identified by IPE event tree top-event, were evaluated:

RW - Reactor building closed loop cooling water (RBCLC) is required to support instrument air which is required to support the main condenser and feedwater systems.

OG - Offsite power is required to support the main condenser and feedwater systems. OG also is an important initiating event in the IPE since it challenges the Division I and II emergency diesels.

AS - Instrument air is required to support the main condenser and feedwater systems.

TW - Turbine building closed loop cooling water (TBCLC) is required to support the main condenser and feedwater systems.

FW - Feedwater provides another RPV inventory makeup capability.

CN - The main condenser and its support systems (circulating water, MSIVs, vacuum, etc) provides heat removal capability.

CV - Containment venting in the IPE provides another capability for heat removal in the long term if the main condenser and RHR are not available.

The analysis of the impact of a fire on system cables was generally performed as follows:

1. The P&Id was evaluated to identify active components in the system such as pumps, valves, and instruments that must operate for the system to function.

2. Components whose failure does not impact the main system being evaluated but does impact another, are included with the other system. For example, failure of a RBCLC MOV that supplies cooling to drywell coolers and does not impact RBCLC supply to

other equipment would be considered with evaluation of drywell cooling.

3. For each of the components identified above, a review process was used. A review of the elementary drawing was performed to determine locations of the power sources, control location and the location of the component itself. Associated devices (relay contacts, switch contacts, process switches, etc) wired in the circuit but controlled by circuits other than the one under analysis were evaluated to determine the impact of fire induced operation of these devices. When a device was identified as being important, it's circuit was included with the primary component circuit. Then the CRS[38] (Cable Raceway System) database was searched to determine the Id of each cable in the primary circuit. Wiring diagrams were used when needed to determine the identity of circuit cables that transit electrical enclosures such as junction boxes, termination cabinets, and switchgear. This data was captured on a diagram that is similar to a cable block diagram (CBD) in addition to other pertinent data. A CBD was developed for each component (i.e, pump and the temperature control loop for RBCLC). A generic analysis was performed on a typical MOV to determine which cables/wires can cause spurious operation of the MOV, if they were shorted to other cables or wires.

4. The results of this analysis are tabulated in tables[29] which include the system, component, critical cables, effect on the component from cable failures, and impact on the IPE. The following codes are used to describe the effect of cable failures on components:

   T = trips or changes state
   FAI = component fails as is
   D = component is depowered
   FO = component fails to the open position
   FC = component fails to the closed position

   The impact on the IPE tracks whether a partial system failure occurs from the cable effect. For example, one of several redundant success paths may be impacted or complete failure of the system may occur.

5. The resulting database from item 4 above is queried against the cable database[28] (the link between the two databases is the cable) which identifies cable raceways, fire areas, and fire zones for each cable. The resulting database is provided in tables[29] and includes the information developed in item 4. Table 4.6-1 provides an example table of results for loss of offsite power (LOSP). Table 4.0-1 summarizes the resulting impacts on IPE top events for all systems and functions evaluated.

4.6.1.2 System Specific Summary

This section summarizes non Appendix R system database development, including impacts on the IPE.

<u>RBCLC</u>
RBCLC is an important support system because its failure results in loss of instrument air which leads to loss of both feedwater and the main condenser. This not only results in a plant shutdown, but also the unavailability of these systems to support safe shutdown. The RBCLC pumps and temperature control instruments are included in tables along with the cables and their effects. This table also shows the raceway and impact on the IPE by fire area and zone. A number of MOVs which could impact other systems are not included here (i.e., 2CCP*MOV15A & B, 2CCP*MOV16A & B, 2CCP*MOV17A & B, 2CCP*MOV93A & B, 2CCP*MOV94A & B) but in the systems they support.

The following nomenclature was developed to document IPE impact of cable failures for this system[29]:

RW1A - fails RBCLC pump 1A
RW1B - fails RBCLC pump 1B
RW1C - fails RBCLC pump 1C
RW3A - fails RBCLC pump 3A
RW3B - fails RBCLC pump 3B
RW3C - fails RBCLC pump 3C
RW - fails RBCLC system (TV108 assumed to fail such that flow bypass occurs)

<u>Offsite Power</u>
Offsite power supplied by the power grid is an inherently stable system. This translates to a high availability for the electric support system. Loss of offsite power causes a plant transient, loss of feedwater and condenser and the start of the diesel generators. The important components needed to supply offsite power are listed in a table along with their cables and the effects of cable failure. This table also shows the raceway and impact on the IPE by fire area and zone. The primary mechanism for an internal plant fire to cause loss of offsite power is the spurious opening of motorized disconnects (MODs) or electrical breakers. Spurious operation of the MODs is expected to fail the disconnects and prevent recovery.

The following nomenclature was developed to document IPE impact of cable failures for this system[29]:

KA - failure of 115KV source A
KB - failure of 115KV source B
KR - failure of crosstie capability between Source A and B (recovery)
KAR - failure of both KA and KR capabilities
KBR - failure of both KB and KR capabilities

Table 4.6-1 shows the results of the offsite power analysis and is provided as an example for this section. The total impact by fire compartment is shown in Table 4.0-1.

Feedwater

Failure of the feedwater/condensate system is both an initiating event and loss of a RPV inventory makeup system modeled in the IPE. The feedwater top event in the IPE covers all systems and components directly concerned with delivery of water to the reactor vessel. The feedwater system and the condensate system was evaluated to determine component failures that could either block injection or divert injection to another location such as the condenser. Operation of at least one condensate pump path, one condensate booster pump path, one feedwater pump path and a delivery path through associated piping without flow diversion is a feedwater success. The important components in the feedwater and condensate systems are listed in a table along with their cables and the effects of cable failure. This table also shows the raceway and impact on the IPE by fire area and zone. Fire induced failure of feedwater is realized via numerous combinations of component inoperabilities (pumps and valves).

The impact of fire damage to electrical distribution cables and the subsequent impact on system components required a special designation for the impact. Components that are powered by a UPS or an automatic transfer switch are failed only when all power feeds are failed. For example the level controller for the feedwater is powered from 2VBB-UPS1B. For this level controller instrument loop to fail because of loss of electric power, the UPS must fail or all three power feeds for the level controller have to fail. Feedwater level control valve 2FWS-LCV10A is failed because of loss of power only when all three electrical feeds are failed. To recognize this impact the following coding is used:

electrical feed A	2FWS-LCV10A%A
electrical feed B	2FWS-LCV10A%B
electrical feed C	2FWS-LCV10A%C

Similarly if these power feeds are common to all three level control valves LCV10A, LCV10B and LCV10C, a similar impact coding scheme is used at the system level, FW%A, FW%B and FW%C. The feedwater system is failed only when all three designators are indicated as being failed.

The following nomenclature was developed to document IPE impact of cable failures for this system[29]:

FW	Loss of all feedwater
F1A or B	Loss of one of two flow paths through Air Ejector Intercoolers
F2A or B	Loss of one of two flow paths through Steam Packing Exhauster
FW1A	Loss of one of three condensate pumps. Failure of the remaining two pumps 1B &1C results in loss of all feedwater.
FW1B	Loss of one of three condensate pumps. Failure of the remaining two pumps 1A &1C results in loss of all feedwater.

FW1C	Loss of one of three condensate pumps. Failure of the remaining two pumps 1A &1B results in loss of all feedwater.
FW2A	Loss of one of three condensate booster pumps. Failure of the remaining two pumps 2B &2C results in loss of all feedwater.
FW2B	Loss of one of three condensate booster pumps. Failure of the remaining two pumps 2A & 2C results in loss of all feedwater.
FW2C	Loss of one of three condensate booster pumps. Failure of the remaining two pumps 2A & 2B results in loss of all feedwater.
FW3A	Loss of one of three feed pumps. Failure of the remaining two pumps 1B & 1C results in loss of all feedwater.
FW3B	Loss of one of feed three pumps. Failure of the remaining two pumps 1A & 1C results in loss of all feedwater.
FW3C	Loss of one of feed three pumps. Failure of the remaining two pumps-1A & 1B results in loss of all feedwater.
FW4A	Spurious closure causes loss of one of two injection paths.
FW%A	Loss of one of three redundant power paths for all three level control valves. Failure of the remaining two paths B & C will result in loss of all level control.
FW%B	Loss of one of three redundant power paths for all three level control valves. Failure of the remaining two paths A & C will result in loss of all level control.
FW%C	Loss of one of three redundant power paths for all three level control valves. Failure of the remaining two paths A & B will result in loss of all level control.
CN1A,..F	Loss of one of six circulating water pumps,
CN2A,B	Loss of one of two condensate transfer pumps
CN3A	Failure of one of two pumps causes loss of steam jet air ejectors. Loss of both steam jet air ejectors leading to loss of condenser vacuum.
CN3B	Failure of one of two pumps causes loss of steam jet air ejectors. Loss of both steam jet air ejectors leading to loss of condenser vacuum.

Instrument Air

The instrument air system (IAS) cables listed in a table will cause a partial loss of the IAS if they experience a fire induced fault. This table also shows the raceway and impact on the IPE by fire area and zone. The cables which supply power to the air dryers are typical of cables not included on the cable block diagram. A fault in these cables will only cause loss of a dryer and air will continue to flow to the loads and the system will remain pressurized. The dryers are simply a section of the IAS piping. There are various IAS solenoid operated valves and other process system valves such as IAS primary containment isolation valves and offgas & condensate process valves whose cables are not labeled IAS and they will not change state due to a fault in an IAS cable. Components in this category will be assessed with their respective systems. The following nomenclature was developed to document IPE impact of cable failures for this system[29]:

AS1A - fails compressor 1A
AS1B - fails compressor 1B
AS1C - fails compressor 1C

Containment Venting

As identified in the IPE, the systems required for containment venting (CV) are instrument air, containment purge, and standby gas treatment. These systems were evaluated to determine which cables would be required to insure that the equipment could perform the containment venting function. A table provides the results of this evaluation and shows the raceway and impact on the IPE by fire area and zone. The following nomenclature was developed to document IPE impact of cable failures for this system[29]:

CVM1 - fails Div I MOVs in the SGTS, but valves can be locally opened or closed.
CVM2 - fails Div II MOVs in the SGTS, but valves can be locally opened or closed.
CVA20" - 20 inch AOV101 fails closed and must be opened locally.
CVDWA - outside drywell AOV110 fails closed and must be opened locally.
SPCVA - outside suppression chamber AOV111 fails closed and must be opened locally.
CVDW - inside drywell AOV110 fails closed and can not be opened locally.
SPCV - outside suppression chamber AOV109 fails closed and can not be opened locally.
CV - fails drywell and suppression pool paths and not recoverable.

Main Condenser

A table discussed above for feedwater includes the impact on the circulating water system and the steam jet air ejector system.

The condenser will be lost when a MSIV closure signal is generated. This will occur if one out of "n" channels taken twice (1/n X 2) are tripped. An impact coding scheme similar to that used for the feedwater system was used.

CMSIVS%A, CMSIVS%B, CMSIVS%C and CMSIVS%D is used to indicate channel failures and each generates a 1/2 isolation trip signal. CMSIVs condition is developed when the appropriate combinations of signals are generated. The following nomenclature was developed to document IPE impact of cable failures for this system[29]:

CMSIV	a specific MSIV closes (transient is assumed to cause all MSIVs to close, but they can be recovered)
CMSIVS	more than 1 MSIV closes (not considered recoverable)
CMSIVS%A,B,C,D	a half isolation signal to the MSIVs occurs, but no MSIVs close
IBMSIV	inboard MSIVs close when nitrogen is gone

TBCLC

TBCLC is a support system whose failure results in loss of both feedwater and the main condenser. This not only results in a plant shutdown, but also the unavailability of these systems to support safe shutdown. The TBCLC pumps and temperature control instruments are included in a table along with the cables and their effects. This table also shows the raceway and impact on the IPE by fire area and zone.

TW1A - fails RBCLC pump 1A

TW1B - fails RBCLC pump 1B
TW1C - fails RBCLC pump 1C
TW - fails TBCLC system (TV104 assumed to fail such that flow bypass occurs)

4.6.1.3 Screening Evaluation

Each fire zone in Table 4.0-1 was evaluated to determine the impact on IPE top events. The results of this evaluation are summarized in Table 4.0-1 and tier II documents[29]. The following are summarized for each fire zone or area:

- Fire Area, Fire Zone, and their Descriptions
- Major Equipment in Zone
- Cable Impacts in Zone
- Summary Impact
- Fire Frequency
- Screening Analysis Summary

"Major Equipment" and "Cable Impact" descriptions summarize the impacts and how these were determined, including assumptions. The following approaches were used to define these impacts:

1. Impacts determined by reviewing all cables in the database that were identified as being in the fire compartment. This more detailed review was accomplished when there was a manageable number of cables in the zone. Fire areas 1, 2, 3 and 4 are examples of where cables were reviewed to identify the impact on safety related systems such as those included in the Appendix R safe shutdown analysis.

2. Critical cables identified for non-Appendix R systems (see Section 4.6.1.2 above) and their locations was utilized to assess impact on normal AC power, main feedwater and the condenser.

3. The Appendix R cable database and success path impacts from the safe shutdown analysis were used. Usually when this is used, it is assumed that all Division I or Division II safety systems are impacted. For example, if the Appendix R safe shutdown analysis indicates that Division I and RCIC are impacted. It is assumed that all Division I safety systems are impacted unless item 1 above is used.

"Summary Impact" includes those IPE event tree top events impacted and the appropriate IPE initiating event that represents the impact.

"Fire Frequency" provides the frequency of a fire in the zone as developed from the FIVE evaluation in Section 4.1. This value is the initiating event frequency used in the quantitative screening analysis.

"Screening Analysis Summary" indicates whether the fire zone can be quantitatively screened out (yes or no) and summarizes the reasons for this conclusion. The screening techniques, described in Section 4.6.1, provide confidence that the risk is low from a fire in a zone that is screened out. Core damage frequency (CDF) estimates in many cases were developed from the results of a fire in another zone. In other words, it was not necessary to propagate all fires initiating events through the IPE model to quantify core damage frequency. When the impact of a fire is similar to that in another area where core damage frequency was already calculated with the IPE, core damage frequency was calculated by multiplying the CDF already calculated by the ratio of the new initiator to the initiator quantified with the IPE.

Quantification with the IPE was performed by identifying an initiating event and its frequency for a specific zone, changing the event tree rules to ensure that the impacts of the fire are modeled, and propagating the initiator through the general transient event tree model. Tier II documents[29] summarize those initiators propagated through the IPE model with the CDF results.

4.6.2. Fire PRA (FPRA) Detailed Analysis[30]

4.6.2.1 Introduction and Methodology

This section documents a more detailed evaluation of fire zones and areas that were not screened out from the initial screening analysis described in Section 4.6.1. At NMP2, fire zones are detection zones and are a subset of fire areas. The fire zones evaluated in the initial screening analysis are synonymous with the definition of fire compartments in the FIVE methodology[25] with the exception of the reactor building. However, the reactor building required detailed analysis in this report anyway as described in later in this section. This analysis requires that the impacts of fires in the remaining unscreened areas (zones or compartments) be evaluated in more detail than in the initial screening.

The initial screening analysis eliminated many of the fire zones and areas from further analysis. Of the 176 areas and zones considered, 35 remain for more detailed analysis. Still, there is conservatism in the initial screening analysis since all components, including cables, in the fire zone are assumed to fail. In addition, the actual contents in the area (e.g., cables) was not always evaluated in detail and may be based on conservative assumptions (i.e., the Appendix R analysis[6] indicated Division I impact and the initial screening assumed that all Division I equipment were failed without evaluation).

The initial screening analysis considered the frequency of a fire in a specific zone given that a fire has occurred in the plant (developed from the FIVE methodology). The screening analysis did not consider the conditional frequency of a severe fire that actually causes the assumed impact. The objective of the detailed analysis is to more realistically evaluate impacts and estimate the frequency of core damage (CDF) by considering the following factors:

- Geometry - the actual spatial location of critical components within the specific zone is an important factor which impacts the time for detection & suppression. Given the right geometry between critical components, fires may not be able to impact all critical components even without suppression.

- Severity - the conditional frequency of a fire that causes significant damage, given a fire in the specific area, depends on several factors such as fire type (i.e., breaker, relay, transformer, pump, cable, transient fuel) and geometry. In fact, some fire types may have limited damage even if not suppressed.

- Suppression - The conditional frequency of a fire that is not detected and suppressed before it can cause an impact and/or propagate and create additional impacts is an important factor.

- All cables at NMP2 are IEEE 383 qualified. Therefore, consistent with past PRAs and FIVE self-ignited cable fires are not considered. The ignition frequency is low based on experience and tests.

- The impact of a fire in some areas is based on assuming that short circuits cause unavailability of the components. Therefore, the probability of a short as well as its recoverability is potentially important.

- The frequency and impact of fires is dependent on the source of fire. Therefore, more detailed scenarios may be postulated for different fire causes.

There are large uncertainties associated with developing the above factors, however, a structured approach utilizing existing data can ensure reasonable results. The FIVE compartment screen methodology[25] (Section 6.0 of EPRI FIVE Report) and fire PRA techniques will be used to address these factors and quantitatively evaluate compartments. This involves identifying targets & fire sources, defining fire scenarios, calculating combustible loading, determining damage, and including suppression where necessary.

4.6.2.2 Summary of Results and Conclusion

Table 4.0-1 summarizes the results of the initial screening analysis from Section 4.6.1 Those zones with an initial screening core damage frequency greater than 1E-6/yr, are evaluated in this section. The results of this more detailed analysis described below are summarized in Table 4.0-2. All locations were screened out below the 1E-6/yr screening criteria in FIVE except for the control room. Also, the analysis provides confidence that core damage frequency would be $\lesssim$1E-7/yr for the typical fire zone in the plant with the exception of the control room. The frequency of core damage due to fires in the control room was estimated to be on the order of 1E-6/yr.

The strategy for detailed analysis in this section depended on the fire location, fire sources, types of critical components in the location, assumptions made in the initial screening analysis, additional design details associated with prevention & mitigation of fires in the areas, and impacts on the IPE model[1].

One or more of the following steps were generally required to screen locations in Table 4.0-2:

- Verify impacts assumed in the initial screening analysis. A number of rooms were not screened initially because they were associated with another critical room in the same fire area. Upon closer evaluation and based on walkdowns, these rooms were easily screened based on insignificant impact.

- Identify fire sources and important components that impact the CDF initial screening calculation. The location of these components relative to the fire source must be defined (i.e., scenarios are postulated). If a single fire can not impact two important systems at the same time due to spatial and geometric considerations, in many cases this provides enough of a reduction factor to screen out the area by defining more realistic, but still conservative scenarios.

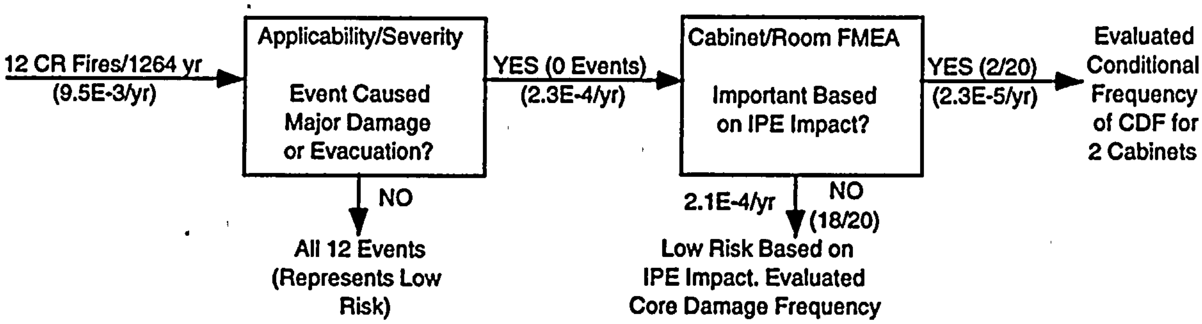
- Partition total fire source frequency in the zone by cause (i.e., cabinet, pump, etc.) to allow more realistic quantification of scenarios. The impact of the source failing as well as the proximity of equipment and cables to the source (i.e., target impacts) are evaluated.

- Automatic detection and suppression was used where it could be shown that this would occur before cable damage occurred.

Analysis of critical combustible loading damage and suppression (FIVE[25] Phase II Step 3) was used consistent with FIVE to support the above detailed screening analysis. This is discussed in Section 4.3.

The most difficult area to screen was the control room because all safety and nonsafety system control cables enter this area. In order to realistically estimate core damage frequency (CDF) for fires in this area, the routing of cables through the area was evaluated as well as the impact of fires in specific electrical cabinets. It was determined that 2 main control room cabinets dominate risk with regard to impact on the IPE. In addition, the fire events that have occurred in the database were evaluated to develop a more realistic estimate of a fire initiator that causes major damage. The following figure summarizes this evaluation.

Control Room (CR) Fire Evaluation



As shown above, none of the 12 events in the database resulted in major damage or the evacuation of a control room. To estimate the frequency of a fire that causes major damage and potential evacuation of the control room, zero events in 1264 years was used to update a prior distribution that enveloped the uncertainty of this event. Then, based on an evaluation of cable routing, the likelihood of cable fires versus cabinet fires, the separation of cables, the PGCC design and detection and suppression capabilities, it was determined that two main control panels dominate the potential risk of fires based on IPE impact. These two panels were evaluated to assess the conditional frequency of core damage given a fire with the potential of causing major damage and control room evacuation. Fires that have less of an impact on the IPE are about an order of magnitude more likely and they were also evaluated to provide confidence that CDF from these scenarios are at least on the same order of magnitude as those evaluated for the two panels.

Human response or uncertainties about response dominates the core damage frequency results as summarized below:

- There is uncertainty on the conditional frequency that the operators evacuate the control room, given the low frequency events being postulated.

- Given that operators do leave the control room, there are uncertainties on human reliability at the remote shutdown rooms, particularly if emergency depressurization is required or there are LOCA conditions. The procedures utilized at the remote shutdown rooms do not assume additional failures outside the Appendix R analysis assumptions.

- There are scenarios where the operators initially decide to stay in the control room and have adequate equipment to control RPV inventory, but later have to leave to recover decay heat removal. The model assumes that control of RPV level is not given up from the control room, thus recovery may be occurring from both the control room and remote shutdown rooms (i.e., service water recovery). The remote shutdown switches allow this, but procedures are not specific in this area.

The following summarizes the control room evaluation results:

Fire Scenario		CDF Results (Annual Frequency)			
Description	Annual Frequency	Baseline	Sens 1	Sens 2	Sens 1&2
Less Significant Fires	2.1E-04	6.2E-07	1.0E-06	4.3E-06	5.3E-06
CRF1 - Panel 852	1.1E-05	3.5E-07	8.9E-07	4.4E-07	1.5E-06
CRF2 - Panel 852	1.1E-05	2.2E-07	2.5E-07	2.2E-07	2.5E-07
CRF3 - Panel 601	1.1E-05	1.7E-07	2.0E-07	2.2E-07	2.8E-07
Total	2.4E-04	1.4E-06	2.3E-06	5.2E-06	7.3E-06

Each of the above fire scenarios are described in detail in Section 4.6.2.3. The following provides a brief explanation for the reader:

Less Significant Fires - Low risk based on IPE impact (section 4.6.2.3)

CRF1 - Fire in panel 852, loss of offsite power scenario 1 (Figure 4.6-1)

CRF2 - Fire in panel 852, loss of offsite power scenario 2 (Figure 4.6-2)

CRF3 - Fire in panel 601, loss of service water (Figure 4.6-3)

Sensitivity case 1 sets human recovery to guaranteed failure when the operators initially invoke the remote shutdown procedure N2-SOP-78[39] and high pressure injection (RCIC and HPCS) is unavailable. No credit is given to RCIC when there is a stuck open SRV. This sensitivity case was provided because SOP-78 is an event driven procedure and emergency depressurization is an event outside the procedure. The model takes credit for the operators returning to symptom based training when these conditions outside the SOP-78 procedure occur. It should be pointed out that the simplified model for "Less Significant Fires" takes no credit for condensate and feedwater systems continuing to provide RPV level control. Therefore, more detailed analysis would be required before drawing conclusions about the importance of emergency depressurization and SOP-78.

Sensitivity case 2 sets the probability that operators initially invoke SOP-78 to 1.0. This allows no chance for the operators to remain in the control room. Typically, human reliability is better in the control room particularly when emergency depressurization is needed. There was no change in core damage frequency (CDF) for scenario CRF2 because the fire impact requires the operators to leave the control room in order to recover. For this reason, human reliability is expected to be better (i.e., CDF decrease) when the operators initially go to SOP-78, but human reliability was assumed not to change in the analysis.

Sensitivity case 1&2 combines both of the assumptions discussed above for case 1 and case 2.

4.6.2.3 Detailed Analysis

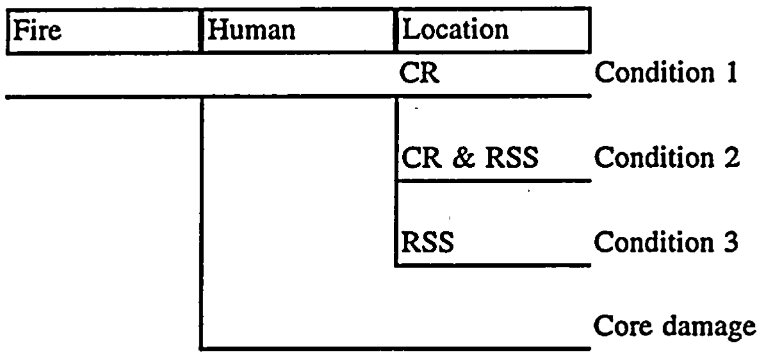
4.6.2.3.1 Control Room (FA26 373.1NZ) and Relay Room (FA24 356NZ)

The control and relay rooms were not evaluated at all during the initial screening analysis (CDF was set equal to the total fire frequency for the room) because both safety divisions and nonsafety systems are located in these areas. It was recognized that there are special preventive and mitigative design features for this part of the plant that needed to be evaluated.

The control room is manned continuously and contains both ionization and thermal type detectors in the subfloor and ionization type detectors in panels. The relay room subfloor also contains ionization and thermal type detectors. In addition, the amount of transient combustibles, such as cleaning fluid, is controlled and there are barriers between panels and within panels to prevent fire propagation. It is considered unlikely that a large fire can either initiate or develop from a smaller fire before detection and suppression. For this reason, a typical fire risk assessment includes analysis of localized panels and/or cable routing areas judged to be most risk significant. The risk significant panels can be identified by evaluating the impact on the plant risk assessment where cables within a panel or panel sections are assumed to fail. Then, more detailed analysis can be applied for those locations that are potentially risk important.

Insights from external event risk assessments, including fires, point to the importance of support systems. This is a logical conclusion because failure of support systems due to a fire has a common cause impact on mitigating systems. Preliminary insights from the initial screening analysis of fires indicate that locations that contain AC power cables are most important. This includes loss of offsite power, because it may not be recoverable, main feedwater and condenser are unavailable, and emergency diesels are challenged which are less reliable than the equipment supplied by emergency AC power given their success. The NMP2 IPE results also indicate that AC power systems are most important to risk. Thus, the analysis of fires in the control and relay rooms will focus carefully on those areas where support systems are impacted.

Accident response to fire initiating events in the control room must consider the fact that human response could dominate the results of a detailed evaluation. This is represented by the "Human" top event in the simplified figure below. Clearly, this can be an important contributor to core damage frequency estimates, especially for fires in the control room.



As shown in the figure, the analysis must also consider that operators may stay in the control room (CR) or while remaining in the control room, attempt recovery with the remote safe shutdown (RSS) procedures (N2-SOP-78, Revision 00) or go to the RSS rooms and give up the control room. These three conditions are characterized below:

Condition 1	This is considered the most likely condition because of panel fire detection, presence of operators, operators have most control & familiararity here, and the initiating event frequency is high favoring small fires. The frequency of a fire that requires evacuation of the control room is less likely, but such an initiating event would tend to make Condition 3 the most likely.
Condition 2	This may be the next most likely condition because depending on fire impact and/or additional failures, the operators may attempt recovery from the RSS while also remaining in the control room.
Condition 3	This condition is considered the least likely unless a severe fire forces evacuation of the control room or a combination of fire severity and additional failures encourage evacuation. The frequency of such an

event is less than the values used in the initial screening analysis. Assuming such an event occurs, if the operators choose to go to the RSS and give up controls from the CR, they give up some capabilities (injection systems) and the RSS procedures are aimed at Appendix R scenarios which do not include emergency depressurization and low pressure injection.

The above discussion alludes to some difficulties with performing fire risk assessments, particularly in the control room. Although it is hard to believe that the operators would completely give up the control room, additional failures to systems not affected by the fire and/or environmental conditions in the control room could influence this decision although the frequency of these events are expected to be low. How the accident scenarios develop and the response of the operators represents a large uncertainty in the above model. The analysis in this section models the above conditions and uses sensitivity studies to assess potential significance.

4.6.2.3.1.1 PGCC Design Review[40]

The design of the Power Generation Control Complex (PGCC), referred to here as the control and relay rooms, was reviewed. The PGCC design includes steel floor sections, termination cabinets, and panels[40].

<u>Floor Sections</u>
The PGCC steel floor sections are designed to prevent fires from initiating, prevent propagation in the unlikely event of a fire, and allow easy access for quick suppression of fires. The following summarizes the design[40]:

- All cables were tested in accordance with IEEE 383. TEFZEL insulated cables are used which have been proven by test to be difficult to ignite and are nonpropagating. Smoke generation is also insignificant. Floor sections are designed to limit the flow of air and exhaust gases by sealing all penetrations. This limits oxygen and eliminates air flow, thus preventing a fire from starting and spreading.

- The only combustible material in the design is cable insulation and the only ignition source is an electrical overload or short circuit. Industry standards, Sandia tests, and NMP2 design suggest that fire ignition to be almost incredible.

- TEFZEL insulation is a high temperature jacket material. Therefore, a considerable amount of energy is required to initiate a fire. The large heat sink provided by the steel floor section keeps temperatures low throughout the structures as demonstrated by tests. TEFZEL cables performed extremely well in fire tests. The fire did not propagate beyond the area of the ignition source, the fire was contained within the exposed duct and temperatures did not cause any degradation of insulation in the adjacent ducts. Another significant result was the lack of smoke from the cables.

- Two thermal detectors and one smoke detector are located in each longitudinal duct. Alarms are zoned to indicate the floor section requiring attention and accessibility is easily provided for manual suppression.

- Although fire tests on the floor section showed that a fire could not be established, a fixed automatic Halon suppression system is installed (easy access was also considered in the design).

- Electrical separation criteria does not allow Division I and II cables within the same floor section.

The location of important support system cables (offsite power, Divisional AC power and service water) at termination cabinets and panels was reviewed along with their routing within the floor sections to ensure that these cables are routed separately. This determination and the above design indicates that the risk of fires in the floor sections is small and can be screened out. Note that the frequency of fires in panels is higher and the spatial location of cables within panels is judged to envelope the spatial proximity of important cables routed in other control room locations.

Termination Cabinets

The termination cabinets contain only cables, thus the frequency of a fire should be less than the frequency of fires in electrical panels in the control and relay rooms which contain relays, lights, and other electrical equipment.

All termination cabinets have bays (typically 4) that are separated by 3/16 inch steel plate. Each bay has a smoke detector.

A termination cabinet fire barrier test was performed and consisted of a fire in one bay and monitoring of circuit integrity of cables in the two adjacent bays. The ignition source was two gallons of paint thinner which burned for approximately 15 minutes. The cables in the adjacent bays were checked and showed to be as good as before the test. A one inch air gap exists between wiring and barriers to prevent surface contact[40].

Distance is maximized between cabinets and bays with regard to separation of divisions. Because of the distance between divisions, the design, the lower frequency of fires within termination cabinets and detection, the risk from fires within termination cabinets is judged to be small and enveloped by other panels in the control and relay rooms. The location of important support system cables (offsite power, Divisional AC power and service water) at termination cabinets and panels was reviewed along with their routing within the floor sections to ensure that panels envelope the risk from fires.

Panels

Panels are also designed such that propagation between panels is unlikely. The design is a little different from the termination cabinets in that a complete barrier is not necessarily provided between bays within a panel. The following summarizes the design and review:

- The main control panels (601, 602, 603, 851 & 852) have barriers between bays on the face of the panel to separate instruments and switches. However, the back portion of these panels is open between bays. There are complete barriers between panels and there are smoke detectors in the panels. Initial visual inspection indicates that most cables enter bays directly from the floor and the routing of cables across bays is minimized. Thus, it appears that most fires would not easily impact two or more bays. For this to occur, the fire would have to propagate horizontally and not be detected and suppressed. Still, these panels appear to be most important from a fire risk point of view in the control room because of the proximity of both divisions and important support systems within a panel.

- The back panels in the control room do not necessarily have barriers separating bays, but sometimes they do. Initial screening assumes that all bays are impacted by a panel fire and more detailed analysis will be performed only where necessary.

- Relay room panels have complete barriers between bays within a panel and each bay has a smoke detector. Thus, initial screening will consider fire impacts within a bay.

4.6.2.3.1.2 Evaluation of Panels

The impact of fires in panels was evaluated. Tables 4.6-2 and 3 summarize the impact of fires in control and relay room panels. Annunciators, recorders, indications and monitors were generally neglected during the evaluation of impacts. Judgments made regarding those panels most important to safety included an assumption that a plant trip would occur due to a fire and conservative assumptions were made on the impact the fire would have on the IPE. Impacts were determined by visually inspecting the panels at the simulator, in the control room, and in the relay room. Drawing references are provided in the table for those cases where the drawings were also used to identify impacts prior to the walkdown.

The frequency of a fire within a panel can be estimated by taking the total frequency of a fire in the control room or relay room and dividing by the total number of panels in the room. The frequency of a fire within a control room panel is estimated as follows:

$$F_{CR\text{-}P} = F_{CR\text{-}PT}/N_{CR\text{-}P} = 1E\text{-}2/40 = 2.5E\text{-}4 \quad (1)$$

where: $F_{CR\text{-}P}$ is the annual frequency of a fire in a specific control room panel

$F_{CR\text{-}PT}$ is the sum total annual frequency of a fire in all control room panels

$N_{CR\text{-}P}$ is the total number of panels in the control room

The above calculations does not include termination cabinets because they contain only cables and are judged to have a lower frequency. The termination cabinets were screened due to lower frequency and impact in the previous section. Also, the above analysis assumes equal probability between cabinets and panels. In actuality, the frequency of a fire depends on the amount and type of components in the cabinet or panel as well as its size (i.e., potential spatial separation of impacts).

The frequency of a fire within a relay room panel is estimated as follows with the same limitations described above:

$$F_{RR\text{-}P} = F_{RR\text{-}PT}/N_{RR\text{-}P} = 2.3E\text{-}4/65 = 3.5E\text{-}6 \qquad (2)$$

where: $F_{RR\text{-}P}$ is the annual frequency of a fire in a specific relay room panel

$F_{RR\text{-}PT}$ is the sum total annual frequency of a fire in all relay room panels

$N_{RR\text{-}P}$ is the total number of panels in the relay room

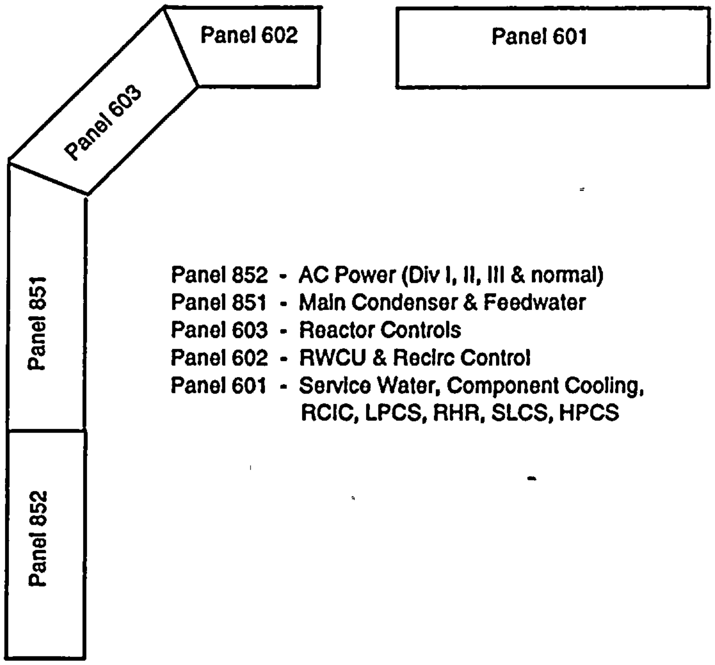
From the above, the frequency of a fire in any one relay room panel is relatively low. As discussed previously, there are barriers between bays and detectors in each bay. Thus, propagation to another bay would be less frequent than 3E-6/yr and propagation to another third bay or another cabinet is even less likely. These considerations in combination with the impacts identified in Table 4.6-3 indicate that the risk from relay room fires can be screened out.

With a few exceptions, a similar argument can be made for the control room panels, except the frequency of a fire in a control room panel is higher. In the control room, we initially assume that all bays are impacted because in many cases there are no barriers between bays.

It was concluded that all panels in the control room can be screened out except for 601 and 852. If fires within the other panels were modeled in the IPE with their respective impacts they would all screen out below 1E-6/yr. In the case of a fire in panel 601 or 852, if it is assumed that all system impacts occur within the panel (very conservative), core damage would occur unless the operators take control from outside the control room (i.e., the remote shutdown panels).

A simplified arrangement of the main control board is shown below with a summary of the major systems by panel. The main control panels were chosen because they are judged to envelope or be representative of where cables come together spatially. The most important panels from a fire risk perspective are 852 and 601. Panel 852 contains electric power which is important from the IPE insights. Panel 601 contains another important support system, service water, which can also impact the balance of plant (loss of cooling to main feedwater and condenser) and emergency equipment (loss of ECCS room cooling and heat removal). Panel 601 also has controls for other important emergency systems such as RHR, RCIC and HPCS.

As shown in the sketch, AC power and RCIC controls are at opposite ends of the control board. Thus, a fire in panel 852 that causes loss of offsite power does not impact RCIC in panel 601. If RCIC is available and runs, the operators have more time to recover offsite power and/or recover from the remote shutdown panels.



Panel 852

Facing the front of the panel, Div I, II, and III emergency AC power run from left to right in separate panel bays with normal AC power controls to the right of Div III (see Table 4.6-2). Thus, it appears difficult to postulate a fire that fails both normal AC power and Div I and/or Div II emergency AC power (Div III separates Div I & II from normal AC power). Also, based on cable routing, it is unlikely that a fire could impact two or more bays unless it is allowed to continue for some time without suppression. In fact, given cable design, it is possible that a fire would eventually burn out and not propagate (limited combustibles).

Based on the IPE results, loss of Div I or Div II AC power as a fire initiator is more important than loss of offsite power or Div III. The frequency of a fire in a specific panel that impacts only one Divisional source of AC power can be estimated from equation (1) above (2.5E-4/yr). This frequency is an order of magnitude less than the frequency of losing Div I or Div II AC power in the IPE (4.3E-3/yr). CDF in the IPE for the loss of one Division AC bus is about 5E-6/yr, thus the fire initiator would screen out below 1E-6/yr. Also, this frequency is judged conservative because the actual frequency for a fire that is required to cause the assumed damage has not been considered and recoverability from outside the control room has not been considered. Thus, the IPE is judged to envelope the risk from loss of one Divisional emergency AC power source as an initiating fire.

The frequency in equation (1) is also less than the unconditional frequency of not recovering offsite power in the IPE (approximately 1E-3/yr at 12 hours) and station blackout risk is dominated by scenarios that lead to core damage in the first few hours after the initiating event. Thus, a loss of offsite power fire initiator is also enveloped by the IPE risk and the fire scenario would screen out below 1E-6/yr. The possibility of recovering offsite power outside the control room would further support this conclusion.

Thus, it is concluded that a fire must impact more than one power source in order to have a possibility of contributing to core damage frequency at or above 1E-6/yr. These scenarios are evaluated further in the next section.

Panel 601
With regard to loss of a single bay, the panel bays judged most important based on the IPE are those containing service water (bays A and B in Table 4.6-2). Loss of service water impacts balance of plant (loss of cooling to main feedwater and condenser) and emergency equipment (loss of ECCS room cooling and heat removal). For example, a fire in bay "A" can impact service water Div I and RBCLC. Impacts on RBCLC and TBCLC mean that the balance of plant may not be as easily recoverable. The frequency of a fire in a specific panel that impacts only one Division of service water can be estimated from equation (1) above. A similar initiator was included in the IPE at a higher frequency (SAX = 6.6E-4/yr) and total core damage frequency from SAX is 3.2E-7/yr. Also, the fire frequency is judged conservative because the actual frequency for a fire that is required to cause the assumed damage has not been considered and recoverability from outside the control room has not been considered. Thus, the IPE is judged to envelope the risk from partial loss of service water as an initiating event due to a fire and these scenarios can be screened below 1E-6/yr.

It is concluded that a fire must impact both divisions of service water in order to have a possibility of contributing to core damage frequency at or above 1E-6/yr. These scenarios are evaluated in greater detail below.

4.6.2.3.1.3 Evaluation of Panels 852 and 601

In the previous section, it was concluded that a fire in these panels would have to impact at least two panel bays or cables entering two panel bays to have a potential impact on risk. These scenarios are evaluated in detail in this section.

Appendix R Review
The assumptions used in estimating the impact of a control room fire defines the capabilities of the remote shutdown system. If the conditions realized by the fire are outside of the Appendix R assumptions, then the remote shutdown systems may not be capable of responding to the effects of the fire. A key assumption used in the Appendix R control room analysis was that only one spurious signal need be considered. This spurious actuation is caused by a single output relay or device. This single signal usually impacts only a single division. Usually this assumption of a single spurious actuation is acceptable from a real world perspective because many time logic signals are developed from two independent divisions/channels that are located in two different panels and are brought together at the final actuating device. However, there are some system level logic signals that are developed within a division. ADS, RCIC high vessel level and HPCS functions are developed within a single division. In the ADS system, spurious actuation of two relays located in the same panel is required for system level ADS actuation. In the other two systems, a single relay can cause high vessel level isolation actuation. In the HPCS system, a single relay can cause loss of injection.

Another key assumption concerns the isolation of circuits between controls from the control room and controls from the remote shutdown panel. Transfer switches are used to isolate the effects of short circuits in one location from affecting control from the other location. The critical premise is that when the transfer switch is transferred, the systems and components are fully operational.

Review of Remote Shutdown Procedure & Human Response
Procedures N2-SOP-78 & N2-OP-78 were reviewed to determine how they coordinate together from a human factors perspective. N2-SOP-78 "Control Room Evacuation" provides guidance for the evacuation of control room while N2-OP-78 "Remote Shutdown System" gives detailed guidance concerning the operation of the Remote Shutdown System (RSS) at the Remote Shutdown Panel (RSP).

The focus of this evaluation is to determine whether the potential exists for nonrecoverable operators errors (errors of omission) that by themselves causes a loss of a remote shutdown function. Operator errors committed during the early stages of the evacuation that impact RCIC are the most important because there is no alternative to RCIC at the RSP and the time for RCIC recovery may be short. Operator errors that cause loss of a DG due to loss of cooling are not recoverable if they exist for more than a few minutes. For each of the above two systems, functional failure modes and their potential causes that can be related to operator error are identified. Additionally operator errors that could lead to a LOCA were evaluated. Key items concerning the severity of operator errors are the following:

Time available to correct the error, i.e. the time until the error develops into a nonrecoverable situation.

Information available to the operator that an error has been committed.

Participation of different personnel in performing the required operator actions and subsequent backup actions.

Where there is feedback, alarms, conditions or indication that alerts the operator to the error, then recovery is possible if time is available. Otherwise, the error may result in component failures that are nonrecoverable.

Procedures N2-SOP-78 & N2-OP-78 were evaluated to identify where the potential exists for operator errors that are not fire location specific, i.e. common to all control room fire locations. In addition, the effects of operator error for fires at the three identified locations in panel 852 and 601 is examined. This analysis primarily focused on achieving and maintaining hot shutdown and preventing a LOCA while starting the RHR system in the shutdown cooling mode.

Failures of the RCIC system can occur due to fire induced failures in the circuitry, a fire or operator created condition that causes high reactor vessel level and water induction in the

RCIC steam line, a stuck open SRV or failure to control RPV pressure (i.e., MSIVs fail open and pressure regulator failure).

Fire Induced Circuit Failures

Failures in the RCIC circuitry are recoverable via operation of the transfer switches at the cable chases or remote shutdown panel. The probability of a hot short causing irrecoverable failure of a RCIC MOV was evaluated in a previous study[41] and found to be an insignificant contributor to RCIC unavailability.

RPV Overfill

Fire induced failures that impact feedwater level control, RPV Level 8, HPCS or RCIC level controls and subsequently lead to RPV level increases into the RCIC steam line before operators have manned the RSP were considered. If any of these events occur and operators fail to stop prevent the overfill, RCIC is probably not recoverable. Loss of RCIC and HPCS requires the operator to depressurize and use low pressure injection, a practice that is not covered by the remote shutdown procedure. The operators have RCIC control at the RSP and also ample time to recover. In the case of a HPCS or feedwater overfill, the operators have less time (because of the high flow rate) and the HPCS pump controls are located at the HPCS switchgear.

Feedwater flow is terminated per procedure: CSO trips the feed water pumps in the control room and then proceeds to the West cable chase and operates switches at 2CES*PNL417. This action also trips the feedwater pumps. The Switchgear Rounds operator verifies that the feedwater pump breakers are tripped.

HPCS is terminated by procedure if the vessel cannot be maintained below 195". For this condition to occur there must be additional operator errors or some malfunction in the HPCS controls, either fire induced or random failure.

Loss of RCIC from multiple operator errors and/or equipment failure resulting in failure to control/isolate HPCS or feedwater is judged to be small in comparison to RCIC normal unavailability and unreliability.

Failure to Isolate the RPV

The vessel is isolated by the CSO using the MSIV & Drain Valve Manual Isolation. The Control Room E Operator deenergizes the MSIVs by opening breakers #3 & #4 at panel 2VBS*PNLA100 and breakers #3 & #4 at panel 2VBS*PNLB100.

Operator errors committed by two different operators leading to a failure to isolate the RPV are considered to be very unlikely and are not considered further. Also, failure to isolate MSIVs does not necessarily prevent RCIC success unless the other failures occur (i.e., bypass is open due to pressure regulator failure).

Operator Errors at RSP
Failure to transfer the transfer/isolation switches to local/actuate positions will not generate a nonrecoverable condition except in the following cases:

Operator fails to transfer a sufficient number of controls to the remote shutdown panel

Operator fails to control vessel level and RCIC is lost

Failure to transfer sufficient controls to the remote shutdown panel results in a loss of status lights at the RSP and a visible indication that some switches are out of alignment. Based on the fact that the CSO, SSS/ASSS, STA, Control Room E Operator and the Inplant Operator are all at the RSP, there will be sufficient verification and opportunity for recovery of the correct switch positioning, the frequency of this event is exceedingly small.

Shutdown Cooling LOCA
While valving in the shutdown cooling mode of the RHR, the possibility of operator error draining the RPV to the suppression pool was considered. The procedure contains a caution statement as to the consequences (RPV drain down)if 2RHS*MOV1A(B) is not closed when 2RHS*MOV113 is opened, a procedural step to verify 2RHS*MOV1A(B) closed and a procedural step to monitor RPV water level when opening 2RHS*MOV113 and close valve if level decreases. In addition, there are electrical interlocks to prevent this scenario. Therefore, this event is considered highly improbable and was not modeled.

Fire in Panel 601 - A fire in panel 601 can cause individual SRV or ADS actuation, loss of service water, and/or loss of ECCS systems. However, not all of these events happen together. RCIC could be in a tripped condition prior to recovery at the RSP panel thus complicating recovery. Loss of the control room circuits for service water can be recovered by operating the transfer switches. Failure to operate the transfer switches causes RSP indication lites for these circuits to be extinguished and the position of the transfer switch is visually observable. However, if any one of these switches are not transferred their is a potential for nonrecoverable damage. If switches 18 or 19 are not transferred but switches 9 and 17 are transferred, then the service water pumps can operate at shutoff head which will result in pump failure. Given that there is feedback to the operator in the form of mispositioned switches and dark indication lites and the pump failure requires that the pump operates without cooling for some period of time, recovery is very likely.

Fire in Panel 852 - A fire in panel 852 can cause loss of offsite power to both Division I & II systems, cause loss of service water to an operating EDG (only one at a time) or loss of EDG operability from the control room. Loss of offsite power due to a panel fire and failure of the service water outlet valve in the closed position can damage the EDG if the condition is allowed to persist. If the operators allow the EDG to operate for a sufficient period of time without recovering service water flow to the EDG then nonrecoverable damage to the EDG will happen. Because the EDG sequencing relays are not located in the control room, a fire induced LOSP will result in a normal EDG loading and service water will be operating before the RSP is operational. There will be no interruption in service. When the transfer switches for the service water pumps and valves are transferred, the pumps and valves do not automatically change position. Therefore, failure of the service water EDG outlet cooling water valve in the closed position while the EDG operates is the only nonrecoverable failure for a fire in panel 852.

- Potential Limitations With Existing Procedures

The following limitations were identified with the existing procedures which taken together could be relatively important:

- Control Room Evacuation - the symptoms for control room evacuation suggest that a relatively insignificant event could lead to evacuation. This creates uncertainty with regard to what conditions really lead to evacuation. From experience and informal discussions with operations personnel, the perception is that evacuating the control room would be a last resort and the operators would utilize air packs. In most cases, the control room is the preferred location for plant recovery.

- CR versus RSP - once SOP-78 is entered, one interpretation would be that the control room is evacuated. In reality, it is possible that the operators would want to use the RSP to enhance plant recovery (i.e., long term heat removal) while remaining in the control room. To give up control of RPV inventory and other short term critical functions to the RSP may not be appropriate. Flexibility to utilize both the control room and the remote shutdown panels should be considered.

- RSP & SOP - given that SOP-78 is required and is being used, it is possible to be outside the event driven procedure. For example, the procedures do not address RPV depressurization and low pressure injection (i.e., a stuck open SRV or RCIC unavailable) or explicitly indicate whether the EOPs are still being used (i.e., symptom based procedure).

- Disabling BOP - given that SOP-78 is entered, procedures have operators close MSIVs, trip main feedwater pumps before leaving the control room. This may not be appropriate depending on the actual fire impacts.

Possible Enhancements to Procedures & Training

There is a spectrum of possible opportunities for reducing the risk associated with a control room fire. The following suggestions are provided for consideration:

Modify N2-SOP-78 and operator training to provide guidance on using HPCS and low pressure injection if the RCIC system is inoperable. A decision should be made as to whether this is adequate or whether EOPs should be included, etc.

Develop additional guidance and training that focuses on what conditions and circumstances would really force the operators to evacuate the control room versus situations where both the control room and RSP could be utilized.

Develop additional guidance and training that could be utilized prior to the SOP to evaluate the impact of a fire prior to disabling the equipment. For example, some symptoms may include:

location and severity of the fire

level of actual damage or potential damage

The above data could be used to determine if there is a need to trip the feedwater system or to isolate the reactor from the condenser by closing the MSIVs. It could also be used to determine if the control room is to be evacuated totally or partially. Partial evacuation covers the situation where the control room is still manned but one or more features of the remote shutdown may be controlled at the RSP. This enables the operators to utilize the available equipment in the control room and to recover fire damaged equipment at the RSP.

Fire Frequency

In the previous section, panels 852 and 601 were identified as most important and it was determined that a fire would have to impact two systems in order for core damage frequency to approach or exceed 1E-6/yr. The frequency of a fire per cabinet in the control room was also developed and used to assess the importance of cabinets. This frequency is about 2.5E-4/yr per cabinet. The conditional frequency of fires that impacts more than one system, requires recovery from the remote shutdown panel, or other failures that lead to core damage frequency were not estimated. However, if a human error probability of 1E-2 or greater was used, these scenarios would not screen out without a more detailed evaluation. For this reason, the control room fire database[25] was reviewed and the frequency of fires in the control room redeveloped more realistically.

The frequency of control room fires used in the initial analysis was based on 12 fires in 1264 reactor years[25]. These 12 fire events were all assigned to the "Electrical Cabinet" category. The following summarizes the events and their potential applicability to NMP2:

- One event was associated with an oven that does not apply to the control room at NMP2, but may apply to the operators lunch room.

- One event was associated with an electrical fault in a circuit card. This could apply to the annunciator panel portion of panels 852 and 601. The annunciator panels contain cards, are in the upper portion of the panels, but is a self contained enclosed box such that fires could not propagate easily out of the box. This area of the panel is some what removed from areas that contain cables that could impact two systems.

- One event was associated with a shorted wire which was pinched with a cabinet door.

This would be difficult based on the PGCC design, but is possible. Still, the consequences of pinching a single low voltage wire in these panels should be localized and of limited impact.

- One event was associated with CRD cabinets at a PWR. The sequence of events appears to be unlikely at the panels being evaluated here for a number of reasons. At NMP2, CRDs utilize hydraulics/low power versus high power electrical mechanical, electrical is interlocked to prevent parallel supplies, and high power paralleling, if it occurred, would not apply to these panels.

- One event has no description available except that it occurred during an outage. Our judgment is that this could not have been a significant event, because if was it would be known in the industry.

- Seven events were associated with relays (5) and resistors (2). All of these events are applicable to NMP2. However, the location of resistors and relays is near the front face of the panels versus the back portion where cables for two or more systems are relatively close together. Given the amount of combustibles associated with relays and resistors, their location within the panel, the fact that barriers on the face of the panel prevent propagation between systems, and the cables of concern are nearer the back of the cabinet, it would appear that these events could not easily impact multiple systems at NMP2.

Based on the above review, some events do not appear applicable to the two panels under evaluation and the others resulted in relatively minor impacts. It can be concluded that no event in the database caused the impact that is being evaluated here (i.e., failure of two systems). It can also be concluded that no event has resulted in control room evacuation. If either of these consequences had occurred it would be well known to the industry.

The frequency of a fire in the control room that causes significant damage and/or possibly requiring recovery from outside the control room is less than 1 event in 1264 reactor years (<1/1264=7.9E-4/yr). To estimate this frequency, a prior distribution was developed assuming a lognormal distribution with a 95th percentile of 1E-2/yr (i.e., 12 events/1264 years) and a lower bound 5th percentile of 1E-5/yr. The resulting mean of this distribution was 2.9E-3. A bayesian update was performed utilizing 0 events in 1264 years as the appropriate evidence for fires in the control room that causes significant damage and/or possibly causes evacuation of the control room. This resulted in a mean frequency of 2.3E-4/yr.

The conditional frequency that the fire occurs in panel 852 or 601 was estimated in the previous section by assuming the frequency is equally distributed over all panels and cabinets in the control room (40 electrical cabinets not including termination cabinets). This approach was also utilized here. There are potential conservatisms and nonconservatisms associated with this approach. The main control panels are larger than the typical average cabinet. However, the average density of relays, resistors, circuit cards and other causes associated with the 12 precursor events is judged to be less in panels 852 and 601. On the other hand, utilizing 0 events in 1264 years for the frequency of fires with major impact also removes these precursors from the frequency calculation. Because an additional reduction factor within these panels could be developed by considering the area within the panels where a fire could have the impact of concern, utilizing a conditional frequency of 1/20 for each panel is believed to be conservative.

The frequency of a fire in panel 852 or 601 that causes significant damage requiring the operators to recover from the remote shutdown rooms can be estimated by multiplying 2.3E-4/yr times 1/20 = 1.1E-5/yr.

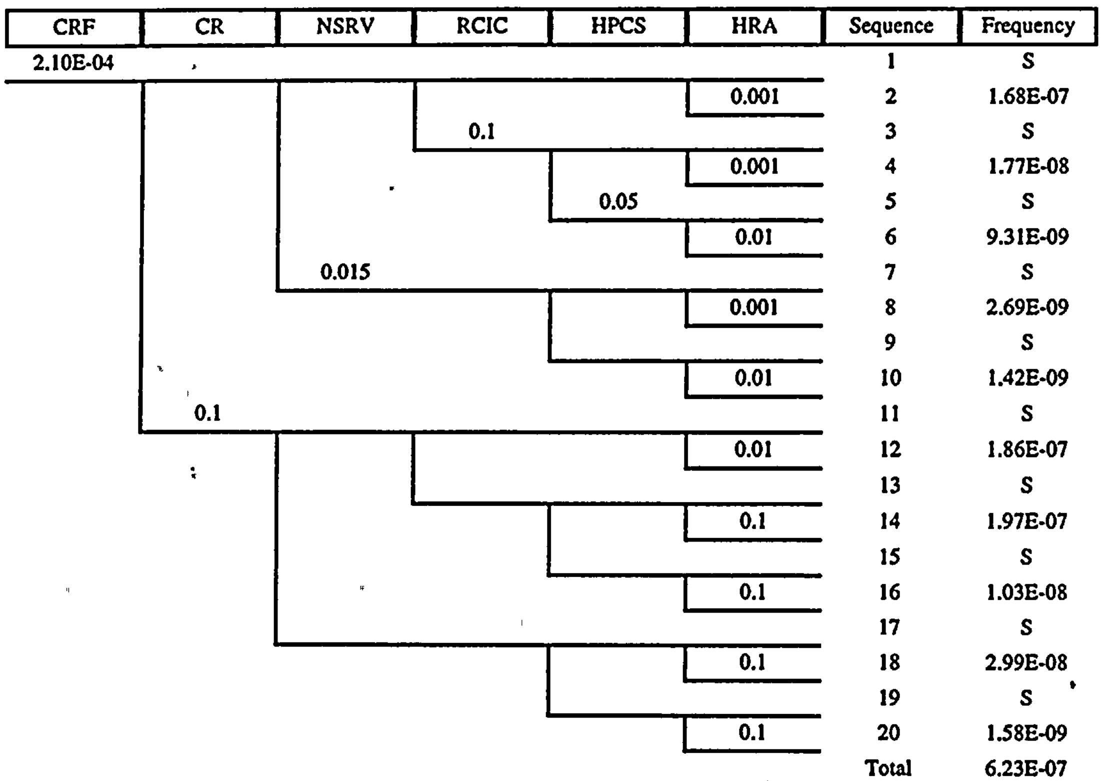
Other fires that have less of an impact on the IPE are about an order of magnitude more likely, their frequency is equal to (2.3E-4/yr)*(18/20) = 2.1E-4/yr. These events were not evaluated in detail, but were evaluated to provide confidence that CDF from these scenarios are at least on the same order of magnitude or less than determined for panels 852 and 601 (described later in this section). The reliability of equipment needed to prevent core damage is relatively high since by definition the impacts of fires in other cabinets or locations is less severe that panels 852 and 601 which were evaluated in greater detail. Therefore, operator errors and/or utilizing the remote shutdown procedures which may lead to reduced equipment capabilities for core damage prevention would have to be important.

<u>Less Significant Fires</u>
The case where the operators leave the control room versus stay in the control room was considered for these less significant fires at 2.1E-4/yr. Leaving the control room may tend to limit recovery capabilities at the remote shutdown panels versus the capabilities that exist in the control room. The remote shutdown procedure is event driven. This procedure can only accommodate a few identified events. If the event is outside the procedure, the operators must return to their symptom based procedures (EOPs). Utilizing the remote shutdown procedures rather than the EOPs may lead to reduced reliability in responding to the event. Since the initiating frequency is on the order of 2E-4/yr or less, the unreliability in equipment, procedures and operators would have to be greater than 5E-3 for CDF to be 1E-6/yr. These unreliabilities were assessed by reviewing the remote shutdown procedures (N2-SOP-78 and N2-OP-78), considering the equipment capabilities at the remote shutdown panels, and discussing these scenarios with plant operators. The following summarizes the conclusions:

1. Equipment capabilities outside the control room (i.e., the remote shutdown rooms, switchgear rooms, and other local control capabilities) were evaluated. In implementing N2-SOP-78, MSIVs are closed, ADS (both manual and automatic are disabled, but four SRVs are operable from the remote shutdown panels) is disabled, feedwater pumps are tripped, and service water MOVs are closed preventing use of RBCLC and TBCLC. Thus, the balance of plant and ADS can be assumed to be unavailable at the time N2-SOP-78 is implemented. Service water is aligned to have one pump operating per Division. Only when N2-OP-78 is implemented from the SOP are HPCS and the condensate pumps tripped. This is only done if there is adequate RPV level. With regard to RPV level control, RCIC, 4 ADS, RHR "A" and "B" can be controlled from the remote

shutdown panels and HPCS would not be made unavailable unless it was not needed. Other low pressure injection systems could be locally aligned if required. There is sufficient redundancy such that equipment unreliability is judged to be less than 1E-3 even if the fire impacts portions of these. The one exception is when loss of offsite power is caused by the fire because the reliability of diesels is much less than the numerous redundant systems that are supplied by the diesels. However, the conditional frequency of losing offsite power reduces the frequency of these events and loss of offsite power is addressed in the panel 852 evaluation.

2. Some limitations and potential weaknesses were identified with the procedures. The following model was developed to assess these potential limitations:



The remote shutdown procedure (N2-SOP-78) assumes that RCIC is available, there is no stuck open SRV (no LOCA conditions), and the EOPs are not explicitly used with the remote shutdown procedures. Since Appendix R fire evaluations do not consider design basis accident conditions such as LOCA or equipment failures that are not fire induced, the remote shutdown procedures do not explicitly address recovery under LOCA conditions. A plant transient induced stuck open safety relief valve (SRV) was considered as well as the need to emergency depressurize. The probability of a stuck open SRV in the IPE is 1.5E-2. The conditional frequency associated with operators leaving the control room in the model is 0.1 (CR failure). This frequency is obviously not 1.0 because they are trained to utilize air packs and stay in the control room where practical. However, if this frequency was set to 1.0 and the other assumptions kept the same, the total core damage frequency would be about 4E-6/yr. Also, in the above model, credit is given to operator actions in the remote shutdown room when emergency depressurization is required. Just because the remote shutdown procedures do not explicitly address LOCAs and emergency depressurization, the operators are still aware that depressurization and low pressure injection are obvious success paths. If no credit was given to the operators in the above model when they are in the remote shutdown rooms and emergency depressurization is required, core damage frequency would be about 1E-6/yr. Based on these considerations, CDF is realistically judged to be <1E-6/yr. In addition, the sensitivity results discussed here show that uncertainty about human response at the remote shutdown rooms when emergency depressurization is needed is important.

3. Operator reliability during a fire in the control room is another uncertainty associated with evaluating CDF as discussed above. The most critical time for the operators could be during the initial stages of a fire when there may be confusion, spurious signals, smoke, deciding on whether to evacuate, and etc. Thus, if we could postulate a fast moving event that resulted in early core uncovery, this event along with the need for quick operator response may be important. A stuck open SRV could potentially reduce the time for operator action and is described above. An ADS actuation as the result of a fire would be a severe transient especially if ADS actuation occurred before a reactor scram occurred. Three locations were found in the control room where a full ADS actuation is possible (also bypasses time delay). However, two hot shorts are required and low pressure injection systems are likely not effected. The frequency of this unanalyzed event can be estimated as follows:

   2.1E-4/yr*ADS*Short1*Short2 = 2.1E-4/yr*0.1*0.1*0.1 = 2E-7/yr

   where ADS is the conditional frequency that the fire is in one of the three locations where ADS can be actuated and Short1 and 2 are the conditional frequency of a hot short. This result does not consider the possibility that automatic low pressure injection will prevent core damage.

   Although the likelihood of an event that immediately challenges the operators is small, the reliability of the operator during fires, especially outside the control room, most likely dominates our uncertainty and estimates of core damage frequency. However, this frequency is low, on the order of 1E-6/yr, because as described previously, 2.1E-4/yr is a conservative estimate of fires that leads to control room evacuation and the operators should be more reliable in the control room unless equipment impact is significant.

Assuming that fire initiators in Panels 852 and 601 are the most important to risk as concluded above for fires in the control room, the next step is to assess the conditional frequency of core damage for these events.

Core Damage Frequency From Fire in 852

As described previously, a number of scenarios are possible including loss of offsite power, loss of offsite power and one of three emergency power divisions. All of these scenarios could be recovered within the control room if either Division I or II AC power is available. Even if evacuation is required, there is time to recover from the remote shutdown rooms. The time available depends on other system responses such as success of RCIC, no stuck open SRV, or success of HPCS. There may be difficulties in the long term operating RCIC from the suppression pool without heat removal. However, RCIC will operate from the CSTs for approximately 24 hours. Offsite power is not easily recovered if the fire impacts the 86 lockout relays which are located at panel 852. If the fire burns control cables to service water EDG cooling MOVs just prior to loss of offsite power, the EDGs could run to failure without cooling. These MOVs use a grounded and fused control circuit. A wire to wire or a wire to ground short circuit is all that is needed to fail the MOV in the closed position. This can be recovered from the remote shutdown panel if the operators get there fast enough. Based on a review of cable routing and the potential impact of fires in the back of panel 852, the following two fire initiators were postulated and evaluated in Figures 4.6-1 and 2. Each fire initiator and evaluation is summarized below as control room fires 1 and 2 (CRF1 and CRF2). As shown in Figures 4.6-1 and 2, total core damage frequency is about 3.5E-7/yr and 2.2E-7/yr, respectively. If no credit is given to operator recovery at the remote shutdown rooms when both RCIC and HPCS fail (emergency depressurization required), total core damage frequency is about 9E-7/yr and 3E-7/yr. Thus, the total for panel 852 is about 1E-6/yr if no operator recovery is allowed under these conditions outside the Appendix R assumptions.

Control Room Fire 1 (CRF1), Figure 4.6-1

Normal offsite power cables to Division I and II AC power (86 lockout relays actuate and cannot be reset) are in the vicinity of cables that could impact Division II and III switchgear (at the 4KV and 600V levels), and Division II and III service water MOVs to the EDG (valve can fail closed if these wires are impacted before loss of offsite power). Thus, nonrecoverable loss of offsite power is assumed to occur at the Division I and II switchgear. Division III is assumed to be lost and not recoverable (i.e., not recoverable from the remote shutdown panels). Division II is assumed to be lost due to breakers tripping, but these can be recovered from the remote shutdown procedures. The potential for irrecoverable failure of the Division II diesel is considered possible if the EDG service water MOV fails closed prior to loss of offsite power and the operators do not trip the EDG or recover its cooling before failure. Division I AC power is available if its EDG is available and RCIC should be available from panel 601.

Based on these initial conditions, operators can recover from the control room if the Division I EDG is available. The unavailability of other Division I systems is less than the EDG. If the Division I EDG is unavailable, the operators will have to leave the control room to recover Division II AC power. The following summarizes the sequences in Figure 4.6-1:

Sequence(s)	Description
1 & 2	The operators initially stay in the control room (CR success), there is no stuck open SRV due to plant transient (NSRV success), RCIC is available, and the Div I EDG is available and continues to operate for 24 hours (EDG1 success). In sequence 1, the operators successfully control RPV level and align decay heat removal. Operator reliability is the best here because they initially decided to stay in the control room and equipment is available to shutdown the plant from the control room.
3 & 4	The operators initially stay in the control room (CR success), there is no stuck open SRV due to plant transient (NSRV success), RCIC is available, Div I EDG fails (EDG1 failure), and Div II EDG is available and operates for 24 hours (MOV2 and EDG2 success). This leads to a station blackout until the operators leave the control room and recover Division II AC power from the remote shutdown room (RSS). In sequence 3, the operators successfully control RPV level and align decay heat removal from the RSS. Operator reliability is less here because they initially decided to stay in the control room, but equipment failure requires another decision to leave or utilize both locations to shutdown the plant.
5 & 6	Both EDGs fail leading to an irrecoverable station blackout.
7 & 8	This is similar to sequences 1 & 2 except RCIC fails which requires the operators to depressurize RPV and use low pressure injection sources. Human reliability is not as good as in sequences 1 & 2 because of less time and additional actions.
9 & 10	This is similar to sequences 3 & 4 except RCIC fails which requires the operators to depressurize RPV and use low pressure injection sources. Human reliability is not as good as in sequences 3 & 4 because of less time and additional actions. Also, the RSS procedure (SOP-78) was developed assuming that RCIC would be available (i.e., the procedure does not address recovery with emergency depressurization or LOCA conditions).
11 & 12	This is similar to sequences 5 & 6 except RCIC also has failed.
13 & 14	This is similar to sequences 1 & 2 except there is a stuck open SRV (RCIC can not provide inventory control, but can provide time) which requires the operators to depressurize RPV and use low pressure injection sources. Human reliability is not as good as in sequences 1 & 2 because of less time and additional actions.
15	A stuck open SRV and failure of Division I EDG is conservatively binned to core damage with no credit for operators depressurizing and recovering from

the RSS.

16-30 Similar to sequences 1 through 15 except the operators initially decide to go to the RSS or conditions require this decision. Human reliability is assumed not to be as good as above when recovery could have been accomplished from the control room (16 & 17, 22 & 23, 28 & 29). If recovery is required from the RSS (18 & 19, 24 & 25), human reliability is assume to be as good as above.

Control Room Fire 2 (CRF2) Figure 4.6-2
Normal offsite power cables to Division I AC power are in the vicinity of cables that could impact Division I and II switchgear (4KV and 600V levels) and Division I and II service water MOVs to the EDGs (valve can fail closed if wires are impacted before loss of offsite power). Thus, nonrecoverable loss of offsite power is assumed to occur at the Division I switchgear. Division I and II switchgear is assumed to be lost due to breakers tripping, but these can be recoverable by operating transfer switches at the appropriate transfer switch locations. The potential for irrecoverable failure of the Division I diesel is considered possible if the EDG service water MOV fails closed prior to loss of offsite power and the operators do not trip the EDG or recover its cooling before failure. HPCS (Division III) is not effected by this fire and RCIC should be available from panel 601. Also, note that the Division II switchgear is recoverable from the remote shutdown switches with its offsite power supply, thus, nonrecoverable failure of the Division II EDG is not considered.

Based on these initial conditions, operators have to recover from outside the control room because both Division I and II switchgear are assumed to be lost. The following summarizes how the sequences in Figure 4.6-2 differ from the sequences in Figure 4.6-1 discussed above:

- Recovery must occur at the RSS, thus human reliability is assumed not to be as good for cases where operators decide initially to stay in the control room (CR success).

- HPCS is not impacted by the fire, thus it is included in the model and reduces the frequency of losing high pressure injection sources which would require RPV depressurization and the use of low pressure injection systems. Given RCIC failure, HPCS success provides initial RPV inventory control until operators successfully recover from the RSS (HPCS pump is assumed to fail in the long term without room cooling). Since HPCS control is not available from the RSS, human reliability is penalized for these scenarios.

- There is no loss of offsite power to Division II and III, thus the equipment reliability is better, reducing the frequency of losing high pressure injection sources which would require RPV depressurization and the use of low pressure injection systems.

Core Damage Frequency From Fire in 601
The cables and routing for the ADS valves were examined for panel 601. A fire in the panel at the correct location can cause an ADS blowdown without a prior scram while at the same

time bypassing time delays and LPCI/LPCS pump operating permissive. This happens if there are two wire to wire short circuits in a wire way. The shorts do not have to occur simultaneously because the relays individually seal-in.

Given that the ADS actuation happens, the vulnerability of the injection systems to the same fire was evaluated. The LPCI/LPCS pump controls and the injection valve controls and circuit routing was evaluated to determine if a single fire can cause loss of all injection with the ADS actuation. The circuit routing for Division I ADS and LPCI/LPCS pumps and injection valves are routed together so that a fire can cause an ADS blowdown with loss of Division I injection. Division II & III injection systems are operable. Also, offsite power is available.

The circuit routing for Division II ADS and LPCI pump and injection valves are routed together so that a fire can cause an ADS blowdown with a partial loss of Division II injection, the B LPCI loop. The controls for the B and C injection valves are routed such that a fire that causes Division II ADS actuation potentially fails only the B injection system. Division I & III injection systems are operable.

Therefore, based on the location of system controls and the routing of cables into and out of the panels, loss of all high pressure injection and ADS or all low pressure injection is unlikely.

An analysis[41] considered the change in core damage frequency associated with a proposed modification to prevent the possibility of RCIC MOV hot shorts. The fire postulated was in panel 601, bays B and C, which impacts Division II service water, component cooling, and RCIC. A previous analysis of this panel[41] indicated a relatively low core damage frequency associated with this specific fire. This present analysis is in agreement and has judged that the total loss of service water in bays A and B is the most important scenario at panel 601 as described below.

Loss of all service water is possible since both Divisions of cables are fairly close together in the panel. Loss of all service water should not be as severe as losing AC power as discussed above for panel 852 because there is time for operator recovery actions regarding room cooling and decay heat removal. Core damage can be prevented without service water (i.e., open doors for ECCS room cooling and align containment venting) and without using the remote shutdown rooms. In addition, utilizing the remote shutdown panels would allow recovery of service water. The loss of all service water is evaluated in Figure 4.6-3. This fire initiator and evaluation is summarized below as control room fire 3 (CRF3). As shown in Figure 4.6-3, total core damage frequency is about 1.7E-7/yr. If no credit is given to operator recovery at the remote shutdown rooms when both RCIC and HPCS fail (emergency depressurization required), total core damage frequency is about 2E-7/yr.

<u>Control Room Fire 3 (CRF3) Figure 4.6-3</u>
Division I and II service water cables are in close proximity in the back of panel 601. All

service water is assumed to be lost. The operators have to recognize the loss of service water event which will require RCIC interlocks to be bypassed and eventually service water will need to be recovered to provide decay heat removal or containment venting will be required. If RCIC fails, the operators will have to depressurize the RPV and open ECCS pump room doors in the long term to provide room cooling. Note that the HPCS pump will run for several hours without room cooling, but in the long term service water cooling is required. The following summarizes the sequences in Figure 4.6-3:

Sequence(s)	Description
1 & 2	Operators initially decide to stay in the control room (CR success), there is no stuck open SRV (NSRV success), and RCIC is successful. In sequence 1, the operators have to recognize the loss of service water event and eventually bypass RCIC interlocks or recover service water and room cooling from outside the control room (i.e., RSS). Eventually, recovery is required outside the control room to provide decay heat removal or align containment venting.
3 & 4	Similar to 1 & 2 except RCIC failed and HPCS is successful. HPCS continued success in the long term requires pump room cooling (i.e., service water recovery from the RSS).
5 & 6	Operators have to depressurize the RPV and utilize low pressure injection sources. Pump room doors must be opened to assure pump success in the long term or service water can be recovered from the RSS. As with sequences 1 and 3, decay heat removal success requires actions outside the control room. The reliability of the operators is assumed not as good because there is less time and emergency depressurization is required.
7 & 8	Similar to 3 & 4 except there is a stuck open SRV. Since HPCS can maintain inventory control, the time and response is similar.
9 & 10	Similar to 5 & 6 except a stuck open SRV reduces the time available for the operators to depressurize (RCIC success, not modeled, would provide some extra time).

Sequences 11 through 20 are similar to sequences 1 through 10 except the operators initially decide to evacuate and utilize the RSS. In the case where RCIC is available and there is no stuck open SRV, human reliability is assumed to be as good as the case where they stay in the control room because RCIC controls from the RSS are adequate. Also, service water recovery, room cooling and decay heat removal eventually requires recovery outside the control room even for sequences 1 through 10. If RCIC fails, HPCS control and success is judged more difficult from the RSS. For this reason, human reliability is assumed not to be as good.

4.6.2.3.2 Shift Supervisors Office (FA26 373.2NZ), Training Room (FA26 373.3NZ), and PGCC Computer Room (FA24 357XL)

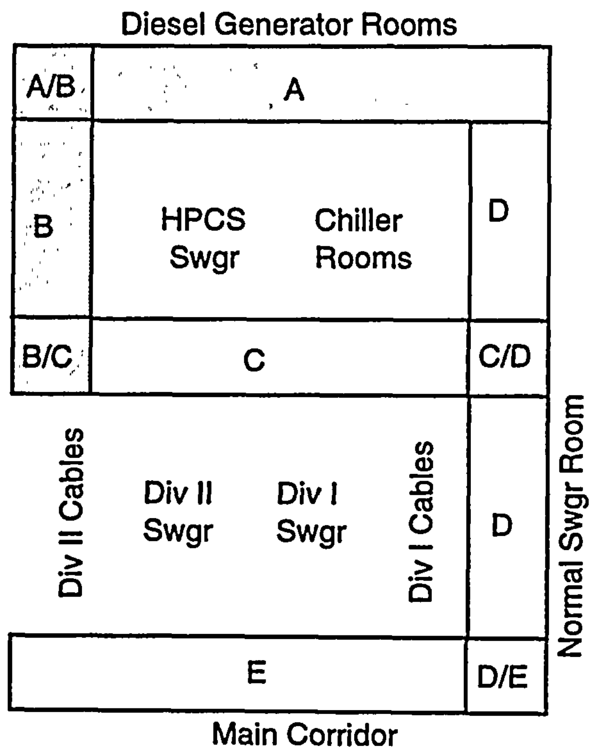
These fire zones were not evaluated at all during the initial screening analysis (CDF was set equal to the total fire frequency for the area) because the spatial database developed for fire areas 24 and 26 did not distinguish between zones 373.1NZ (control room), 373.2NZ (shift supervisors office) and 373.3NZ (training room). Likewise the database did not distinguish between the relay and computer rooms. Thus, the actual cables being routed in these zones have to be evaluated.

There are no safety related or important nonsafety related equipment or cables in the supervisors office or the training room based on a review of electrical drawings and a visual inspection. These rooms are screened out (i.e. core damage frequency <1E-6/yr).

Regarding the computer room, the design review indicates that no safety related (divisional) cables are located in this zone. It is considered possible that a fire could cause a plant trip, but the low frequency of a fire in this zone in combination with the minor impact on plant systems indicates that this zone can be screened out (i.e. core damage frequency <1E-6/yr).

4.6.2.3.3 Corridor El 261 CB (FA88 331NW)

This corridor is very long as shown in the simplified diagram. This diagram shows several sections that were defined for the purposes of documenting walkdown notes. For initial analysis purposes, the corridor was broken into two separate zones with the shaded portion called FA88A and the remaining corridor FA88B. These two zones were identified because FA88A (Sections A and B, including B/C) in the diagram has no automatic suppression (does have smoke detection) and the ceilings are much lower. Where as FA88B, the remaining non shaded sections, have automatic detection and suppression (smoke detection and cable tray water spray) and the ceiling is much higher. Thus, the following strategy was developed to more realistically assess the risk of fires in fire area 88:



FA88A was evaluated to determine the impact of a fire in this zone. Initially, it will be assumed that a fire will cause this impact without a chance for suppression. All nonsafety trays and conduits were found to have no impact on offsite power and the balance of plant (feedwater and main condenser). A single conduit (2CL511GD containing cable 2BYSAGL609) can impact the Division I diesel generator. Another conduit, 2CL510YF, was found to be empty (no cable). Apparently the control cable to the Division II diesel generator was rerouted through 2CL510YH in another fire area as described in the FA88A evaluation below. Also, there is a HPCS (purple cable) in the B/C interface area.

FA88B has automatic suppression. If suppression is successful, no impacts are assumed to occur in cable trays and conduits. This is based on an evaluation of the time to cable critical temperature versus time to detect and suppress the fire. Also, all the impacts are associated with cables in cable trays and conduits up high in the vicinity of cable tray water sprays. There are no cables or cabinets of concern near the floor area. If automatic suppression fails, initially it will be assumed that all impacts identified in the FA88B occur. This includes loss of offsite power, balance of plant systems, and HPCS.

The location of the Division I diesel cable in FA88A which has no automatic suppression is at the opposite end of section A from where FA88B starts. Thus, a fire that impacts this cable and causes loss of offsite power in FA88B is considered unlikely and is neglected.

FA88A can be easily screened out because the only impact of a fire is the Division I diesel and possibly HPCS. Even if we assume an initiating event and loss of the diesel and HPCS, the scenario will easily screen out below 1E-7/yr.

FA88B can be conservatively evaluated by running the FA88 fire initiator through the IPE with HPCS and offsite power failed (KA=F*KB=F*HS=F). Then, this result is multiplied by the unreliability of automatic detection and suppression. This is conservative because the total frequency of a fire in FA88 has been applied to the FA88B portion and additional detailed evaluations of HPCS cables and their vicinity to offsite power and other balance of plant cables has not been considered. The results of this evaluation is 1.9E-6/yr*0.05 = 9.5E-8/yr.

<u>Evaluation of FA88A</u>

Fire area FA88A was inspected to determine if Div I ,II & III diesel generators are lost. The specific goal was to identify which wires were impacted by the fire and did they actually cause the loss of diesel generators. There are 2 conduits 2CL510YF & 2CL511GD in this zone. A query of the CRS2 database for conduit 2CL511GD and a review of drawings EE-9GV-5 and 10A-6 indicates that cable 2BYSAGL609 provides power to 2BYS*PNL204A in the diesel generator room. Loss of this cable causes loss of the Div I DG control circuits for both the engine and the generator. A query of the CRS2 database for conduit 2CL510YF indicated that this conduit is routed from 2BYS*PNL204B to the tray system located in a different fire area. But, there is not any cable in the conduit. To verify that the power feed to 2BYS*PNL204B was not in this conduit, CRS2 was queried to identify the drawing for this panel. Drawing EE-10A-6 indicates that the power feed to 2BYS*PNL204B is cable

2BYSBYL609. This cable is routed to 2BYS*PNL204B via the following raceways: 2CL507YQ, 2TL507Y,2TL510Y & 2CL510YH.

Conduit 2CL510YH is located in the diesel generator control room. It runs from 2BYS*PNL204B out of the control room via the floor. Therefore, this conduit is not affected by a fire in FA88.

Evaluation of FA88B

This section of fire area 88 has automatic detection and suppression. The fire area walkdown identified that the following divisional conduits exit one of the contiguous fire areas and enter FA88B. The cables in the conduits were identified using the CRS2 database. The divisional cables are:

Div I 2HVCAGK290, 2HVCCGK290, 2RPSAGK502, 2LACAGK200, 2LACAGK201, 2LACAGK202

Div II 2LACBYK200, 2LACBYK201, 2LACBYK202, 2HVCBYK206

Failure of each cable was evaluated for the impact on shutdown and the failure of cables was evaluated for breaker coordination and potential loss of the busses that power the cables.

The Division I lighting system cables, 2LACAGK200, 2LACAGK201, 2LACAGK202 are powered from panel 2LAC*PNL100A. These cables supply power to the lighting system. Loss of the emergency lighting power feed is judged to have a minimal impact on the ability to respond to the fire since the required lights are battery backed. The supply breaker to 2LAC*PNL100A is sized to not trip in the event that all three cables have bolted faults.

Cables 2HVCAGK290 and 2HVCCGK290 are powered from 2EJS*PNL102A. Loss of each cable has an impact on the capability to isolate the control room when a high radiation condition exists. Damper isolation or loss of this isolation feature has no impact on the capability to respond to this fire. The supply breaker to 2EJS*PNL102A is sized and coordinated so as to not open if both of these cables have bolted faults.

Cable 2RPSAGK502 is powered by panel 2RPM*PNLB100. This panel provides power to the "B" scram solenoids. Failure of this panel generates a 1/2 reactor trip. Loss of the individual cable generates 1/2 for group 1 scram solenoids. This failure has no adverse impact on the capacity to respond to this fire.

The Division II lighting system cables 2LACBYK200, 2LACBYK201 and 2LACBYK202 are powered from 2LAC*PNL301B. The individual or combined failures of the cable has a minimal impact on the capacity to respond to this fire and is not modeled (see Div I evaluation above).

Cable 2HVCBYK206 powers a heater in the control building HVAC system. Failure of this cable has a minimal impact on the capacity to safely shutdown and is not modeled.

4.6.2.3.4 Division II Standby Switchgear Room (FA19 336XL)

The initial screening analysis assumed that Division II AC power failed, as well as RBCLC and HPCS, given a fire in this location. Walkdowns were performed in support of this more realistic evaluation. The ceiling and cables in this room are very high. Cables enter the cabinets from the top as well as from underneath. There are 7 smoke detectors in this fire zone and an automatic carbon dioxide total flooding suppression system. A more realistic analysis of fires in this zone was performed by considering the impacts of fires within cabinets (electrical cabinet fires), on cables external to the cabinets (transient type of fires), and cabinet fire impacts on cables.

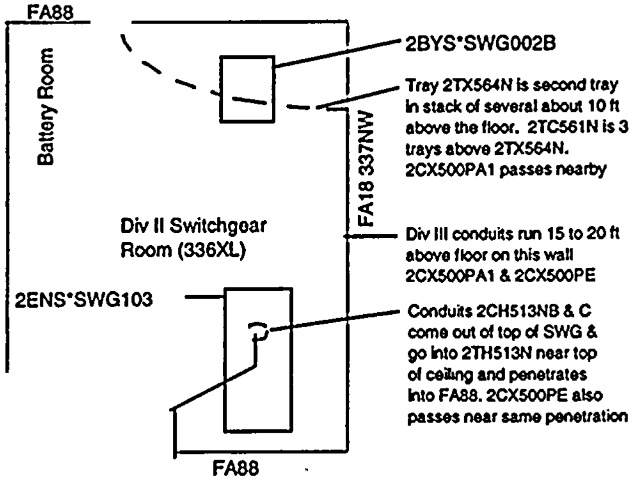
<u>Evaluation of Cables</u>
This evaluation concluded that core damage frequency due to fires external to electrical cabinets is less than 1E-7/yr. This is based on the following:

- The frequency of a fire in this zone is dominated by electrical cabinet fires. The contribution from other causes (i.e., welding, transient, ventilation fans, junction box splices) external to the cabinets is much less frequent. This alone provides over an order of magnitude reduction in the screening analysis results (2.4E-5/yr versus a total of 9.7E-4/yr).

- The proximity of cables that could have the impact assumed in the initial screening analysis was also evaluated. Based on this evaluation, it was determined that Div II cables associated with the 4Kv switchgear, the diesel, and its supplies are not in close proximity with normal AC power feeds. Most Div II cables come from underneath the switchgear (cable spreading below switchgear room) and normal AC power enters the top of the switchgear cabinets. Three yellow (Div II) conduits (2CC534YN, G and M) enter the top of the switchgear. They come out of the floor behind the switchgear, go up the wall, and pass over to enter the top of the cabinet passing near 2CH514N. These cables are associated with tie breaker 2NNS-SWG015 103-8 which are control cables for an alternate offsite supply. Thus, fires external to electrical cabinets are unlikely to cause total failure of Div II AC power which was assumed in the screening analysis. Cabinet fires will dominate the frequency of a total loss of Div II AC power.

  Four critical normal AC power cables to Div II switchgear were found in this room during the initial screening analysis. Two are in tray 2TC561N. The other two are in tray 2TH513N and enter this tray from conduits 2CH513NB and 2CH513NC which come from the top of the switchgear cabinet. The frequency of core damage from a fire that causes loss of normal AC power to Div II switchgear, but does not lead to loss of the Div II diesel, is less than 1E-7/yr (see initial screening analysis of fire area 52 604NZ).

RBCLC cables were also found in this room during the initial screening analysis. Two cables in tray 2TX564N can lead to a loss of RBCLC which would lead to loss of the main condenser and feedwater systems. However, these cables do not enter any cabinets in the room and the tray is not directly above or next to the Div II AC power cabinets. This tray is more than ten feet off the floor (second tray up) and it passes over 2BYS*SWG002B. A fire in this Div II DC power cabinet and potential impacts on the above cable trays (i.e., RBCLC) is assessed later in this section. Another tray containing normal AC power (2TC561N) is in the vicinity but higher up near the ceiling. It is judged that fires that could impact these cables would not likely impact Division II AC power. Thus, fires that impact Div II AC power and RBCLC as assumed in the initial screening analysis are less than 1E-7/yr. Fires that impact RBCLC and not impact Div II AC or DC power can be neglected because core damage frequency would be less than 1E-7/yr (RWX initiator in the IPE is 2.3E-2/yr and core damage frequency from this initiator is 4E-7/yr).



Div III HPCS conduits pass along the wall behind the switchgear. The conduits are 2CX500PA1 and 2CX500PE. However, these conduits do not enter any cabinets in the room and it is judged that fires that could impact these conduits would not likely impact Division II AC or DC power. One conduit (PA1) passes near normal AC power (tray 2TC561N) and/or RBCLC (tray 2TX564N) at one end of the room. The other conduit (PE) passes near normal AC power (tray 2TH513N) at the opposite end of the room where cables exit through a penetration to FA88. Thus, fires that impact normal AC power to Div II switchgear or RBCLC and HPCS is possible in two localized areas. Core damage frequency from these events would be less than 1E-7/yr even without taking credit for suppression.

- It is difficult to impact cables due to transient fires on the floor level because the cables are so high and all cables are IEEE 383 qualified. Even without automatic detection and suppression, it appears that the fire could burn out before impacting the cables. Fire analysis has shown that automatic detection and suppression will occur before cable failures.

Evaluation of Cabinets

The impact associated with an electrical cabinet fire depends on the cabinet and the location of the fire within the cabinet. Table 4.6-4 identifies the 20 electrical cabinets in the room and describes the potential impact of a fire within each cabinet. Based on this evaluation, emergency switchgear 2ENS*SWG103 was identified as the most critical cabinet as summarized below:

- Loss of 2VBA*UPS2B (top event UB in the IPE) results in the loss of Div II automatic ECCS actuation (E2), Div II RRCS (R2) and the ability to open RCIC, LPCI "B" and "C" injection MOVs (IC, IB and LC). Although loss of the UPS was not identified as an automatic plant trip in the IPE, it is assumed for this fire that plant shutdown occurs. The frequency of core damage was conservatively estimated with the IPE to be less than 1E-8/yr, assuming a plant trip and a fire frequency of 1E-3/yr. Thus, this scenario can be neglected.

- Loss of 2BYS*SWG002B (top event D2 in the IPE) results in a plant trip and impacts the availability of several Div II components (i.e., pump start and actuation systems). The frequency of core damage in the IPE from loss of D2 (initiating event D2X=4.16E-3/yr) is approximately 4.3E-7/yr. Since the frequency of a fire initiator with similar impact is less than 1E-3/yr, the frequency of core damage from fire caused loss of D2 is less than 1E-7/yr and can be neglected.

- Loss of 2ENS*SWG103 (top event A2 in the IPE) results in a plant trip and impacts the availability of Div II systems. The frequency of core damage in the IPE from loss of A2 (initiating event A2X=4.3E-3/yr) is approximately 4.8E-6/yr. Since the frequency of a fire initiator with similar impact is less than 1E-3/yr, the frequency of core damage from fire caused loss of A2 is less than 1E-6/yr.

From the above, loss of Div II AC power due to fire is expected to have the most important impact on core damage frequency, although apparently less than 1E-6/yr. For this reason, these scenarios were evaluated in more detail. With regard to a fire in a switchgear cabinet, it will usually start in a specific cubicle and therefore, the impacts suggested in Table 4.6-4 are not expected for all fires. In order for the total impact to occur, either the fire must occur in a cubicle that could result in the total impact or the fire must occur in a cubicle that has limited impacts, but propagates to cause additional impacts before detection and suppression. Fires that do not burn out and can propagate to other cubicles causing additional impacts before detection and suppression are judged to be unlikely and are neglected.

The 4KV switchgear was inspected to determine the fire locations that can cause loss of the bus. A fire in the cubicle where the protective relaying is located can cause the breakers to trip. A fire in a breaker cubicle that faults the upstream (supply side) cables can cause loss of the 4kv bus. A fire in a breaker cubicle that faults the load cables and also causes the breaker to fail as-is can cause loss of the 4kv bus. Alternatively, if the fire causes spurious opening of the breaker or if it causes a fault that is cleared, the fire impact is localized to that load only.

A total loss of power can occur if the protective relaying for the bus is impacted by fire. Total loss of Division II 4kv is assumed for any fire in the following cubicles:

C3226 Bkr 103-3, C3227 Bkr 103-4, C3236 Bkr 103-14

A total loss of 4kv can occur if a fire in an energized cubicle causes a power system fault within the cubicle and also depowers or fails the breaker control circuit before the CO_2 system discharges and suppresses the fire. The fault will be cleared by the upstream breaker, not the branch breaker, resulting in loss of offsite power. After the supply breaker clears, the diesel generator breaker will close onto a faulted bus and quickly open thus preventing recovery of offsite power.

Alternatively, the fire can occur and the branch breaker operates to clear the fault. The CO_2 system discharges and suppresses the fire thus limiting any additional damage to the cubicle. A fire in the following cubicles can cause loss of the Division II bus or loss of the branch load:

C3228 Bkr 103-5, C3230 Bkr 103-7, no Id Bkr 103-8, C3231 Bkr 103-9, C3232 Bkr 103-10, C3233 Bkr 103-11, C3234 Bkr 103-12, C3239 Bkr 103-N2

A fire in an empty cubicle or racked down/out breaker is not postulated to occur since a fault on the supply side cables is actually a bus fault. The following cubicles have their breaker removed or it's control circuit depowered:

C3225 Bkr 103-2, C3229 no bkr, C3237 Bkr 103-15., C3238 Bkr 103-N1.

In summary, there are 3 of 17 cubicles in 2ENS*SWG103, associated with protective relaying, that can lead directly to loss of all Div II AC power. There are 8 of 17 cubicles that can lead to loss of all Div II AC power if a short (fault) also occurs from the fire. Later in this section, this information is used in developing the conditional frequency of fires that cause a total loss of Div II AC power given a fire occurs in 2ENS*SWG103. To develop these conditional frequencies, it was assumed that the total frequency of a fire in the cabinet is dominated by the 11 cubicles that can lead to a total loss of Div II AC power. The other six cubicles are usually not energized or empty and judged to contribute less to the total frequency. Thus, conditional frequencies of 3/11 and 8/11 are used in the analysis.

The 600V AC distribution can be failed by a fire in 4kv bus breaker 103-1 switchgear and the feed for 2EJS*US3. Additionally, a fire at the "X3A" transformer will result in loss of 600V AC. Fires at the load center, 2EJS*US3, can cause loss of all 600V AC. 600V AC MCCs 2EHS*MCC303 bus B is separated from the D bus. A fire in the "B" bus can cause loss of the B & D busses while a fire at the D bus will only cause loss of that section.

A fire at the battery board breakers can result loss of 125V DC. It may cause only the loss of the branch load/supply or loss of the bus. Fire at a battery charger will result in loss of one of the two chargers but not the bus. There is another standby charger available that can be switched in after the fire is out and the room ventilated (local operator action).

A fire at the UPS can cause a non recoverable loss of 120V AC.

The fire frequency developed for this fire area using the FIVE methodology included all cabinets. Some cabinets are empty and some switchgear breakers are completely depowered while a few are in standby. Also, fires in several cabinets will have an insignificant impact. To better model this area, a more detailed evaluation was performed to identify cabinets/cubicles/enclosures that are energized or have been previously shown to be important to risk. The approach taken realized that only powered equipment was likely to fail and only those cubicles that were previously shown to have some affect on risk need be evaluated.

This fire area contains very few exposed cables and they are locates more that 20' above the floor. All of the important cables are in cubicles or cabinets. There are no Div II 4kv cables (and only control wires to the alternate power offsite source) that are routed outside of switchgear in conduit.

The fire frequency was calculated using a combination of fixed and transient combustibles. For this switchgear room, the major source of damage is the cubicles themselves. Transient combustibles are of lesser concern because of procedural controls to limit transient combustibles and there is a cross zone detection system and a 100% coverage automatic CO_2 system.

The total fire frequency is partitioned according to the normal operating status of the cabinet and other features that determine the potential for fire. All loads were subjectively categorized into four groups according to their potential for fire. The first category is the equipment that is normally operating, requires internal cooling and has a high density of internal components;.2VBA*UPS2B and 2BYS*CHGR2B1. The second group of components are normally operating but far from design capacity and have lower density of internal components; 2ENS*SWG103, 2EJS*US3, 2EJS*X3A and 2BYS*SWG002B. The third group of components are panels that are intermittently operating or not operating and are not near their design capacity; 2EHS*MCC303, 2EJS*PNL300B, 2EJA*XD301B and 2EJA*PNL301B. The last group consists of panels that are not normally operating or are at a minimal loading such as emergency lighting panels and transformers, the breaker test station, and the standby charger.

Later in this section, this information is used in developing the conditional frequency of a fire in electrical cabinet 2ENS*SWG103, given a fire in this room. It was decided that using a 1/20 conditional frequency (a total of 20 cabinets in Table 4.6-4) could be optimistic since the frequency of cabinet fires is probably dependent on the cabinet as discussed in the previous paragraph. If we assumed that the total fire frequency is dominated by the six cabinets identified in the first two groups, a 1/6 conditional frequency would be used. A 1/5 conditional frequency is used in the analysis described below.

The frequency of a fire within electrical cabinet 2ENS*SWG103 that causes loss of Div II AC power is estimated with the following equation:

$F_{SWG103/A2} = F_{336XL} * F_{SWG103} * [(3/11) + (8/11)*P_F] = 9.7E\text{-}4 * (1/5) [(3/11 + (8/11)*0.1] \quad (3)$
$= 6.7E\text{-}5/yr$

where: $F_{SWG103/A2}$ is the annual frequency of a fire in 2ENS*SWG103 that results in loss of Division II AC power (A2X initiator in the IPE)

F_{336XL} is the sum total annual frequency of a fire in this room from all causes.

F_{SWG103} is the fraction of fires in the room associated with 2ENS*SWG103. Rather than utilize 1 in 20 cabinets as shown in Table 4.6-4, 1/5 is used based on the evaluation above.

P_F is the probability of a fault causing loss of the switchgear. A value of 0.1 is used.

(3/11) and (8/11) are fractions of fires in 2ENS*SWG103 (cubicles) that lead to loss of bus from protective relay cubicles and other cubicles requiring an additional short, respectively. The development of these conditional frequencies is discussed above..

Core damage frequency can be estimated by taking the ratio of the IPE initiating event frequency for A2X (see previous discussion above) to the above frequency for fires and multiplying this ratio times core damage frequency for A2X. The result is as follows:

$(F_{SWG103/A2}/A2X)*4.8E\text{-}6 = (6.7E\text{-}5/4.3E\text{-}3)*4.8E\text{-}6/yr = 7.5E\text{-}8/yr$

If the probability of a fault in equation (3) is set equal to 1.0, core damage frequency would increase to 2.2E-7/yr.

Another bounding calculation was performed to check the possible upper bound frequency of fires that have minor impact initially, but automatic suppression does not work and the fire propagates to have the impact assumed in the initial screening analysis. The result is as follows:

1.9E-5/yr*0.05 = 9.5E-7/yr

where 1.9E-5/yr is the core damage frequency in the initial screening analysis utilizing the total fire frequency for the room, assuming loss of Div II AC power, HPCS, and RBCLC, and taking no credit for suppression preventing propagation. The 0.05 value is the unreliability of suppression. Thus, the fire is assumed to keep burning to have this level of impact. Even this conservative bounding estimate indicates that core damage frequency will be less than 1E-6/yr.

Evaluation of Cabinet Fire Impacts on Cables
During walkdowns, the potential for cabinet or panel fires to impact cables or conduits overhead was evaluated. This was done because cabinets dominate the frequency of fires in this room and a combination of impacts from the cabinet failure and cables nearby could be important. The following summarizes the conclusions of this evaluation:

- Most fires in the 4Kv switchgear already result in a total loss of Div II AC power. The normal AC power cables are routed straight up toward the ceiling, above a cubicle that does lead to loss of Div II AC power, before be routed in trays. It is unlikely that any fire in this switchgear, which does not result in a total loss Div II AC power, would impact these cables. If detection and suppression are considered, this is even more obvious.

- As described earlier, both RBCLC and normal AC power cables pass over 2BYS*SWG002B. Since RBCLC is much closer to the top of this cabinet, core damage frequency was estimated for the case where Div II DC power and RBCLC are both lost. Using a conditional frequency of 1/5, as used in the previous evaluation of cabinets above, core damage frequency is about 1E-7/yr. If detection and suppression are modeled, the result is much lower.

  Another less likely scenario would also include failure of normal AC power to Div II. These cables are much higher, three trays above RBCLC. Again, core damage frequency was estimated for the case where Div II DC power, RBCLC and normal AC power to Div II are lost. Using a conditional frequency of 1/5, as used in the previous evaluation of cabinets above, core damage frequency is about 2E-6/yr. If detection and suppression are modeled, the result is much lower on the order of 1E-7/yr.

- Other cabinet fires would have much less impact than the cases identified above.

4.6.2.3.5 Division I Cable Chase West (FA16 332NW, 352NW & 371NW)

The initial screening analysis assumed failure of Division I AC power and RCIC, given a fire in this location. This was based on the Appendix R analysis which indicated that Division I and RCIC are impacted. The actual impact on Division I was not assessed. In addition, the BOP cable evaluation identified loss of offsite power and other balance of plant systems being lost. A walkdown was performed to investigate a more realistic evaluation of impacts. The ceiling and horizontal cable trays in this room are high. Taking credit for automatic suppression (0.05 unavailability assumed) in these rooms would result in a core damage frequency less than 1E-6/yr still assuming the worst impact as in the initial screening analysis. Note that only IEEE 383 cables are used and for most fires it is not expected that impacts would occur away from the fire (i.e., hot gas layers, etc) even without suppression (i.e. fire burns out). For these reasons, the focus of the evaluation in these rooms is on identifying impacts that could occur before detection and suppression. This includes electrical cabinet fires and noncabinet fires near the floor as described below.

The following summarizes detection and suppression in each zone:

Fire Zone	Number of Detectors		Type of Automatic Fire Suppression	
	Temp	Smoke	Area Water Sprinkler	Cable Tray Water Spray
332NW	0	5	No	Yes
352NW	0	4	Yes	Yes
371NW	0	4	Yes	Yes

Electrical Cabinet Fires
The frequency of a fire in each zone is dominated by electrical cabinet fires. Therefore, the impact of a fire in each cabinet was assessed and is summarized in Table 4.6-5. Only impacts judged to potentially influence the IPE are noted and in many cases the impacts are based on conservative assumptions (i.e., a cabinet supplies main steam circuits and it was assumed that MSIVs close and condenser is unavailable even though the circuit impacts were not evaluated). In addition, the proximity of cables to cabinets was evaluated during walkdowns and included in Table 4.6-5. If the cabinet is closed (not vented) no additional impacts were considered. In the case of vented electrical cabinets, conduits and cable trays within about 5 feet of the cabinet were considered for the plume and 1.5 feet from the cabinet for radiation heat transfer.

One important finding from this evaluation is that normal AC power is not affected by cabinet fires. This finding alone would reduce the frequency of core damage from cabinet fires below 1E-6/yr. Also, the loss of all Division I equipment was not found to occur due to a single cabinet fire. Thus, the modeling of impacts by cabinet and considering the frequency of a fire/cabinet would further reduce core damage frequency.

Noncabinet Fires
The frequency of fire due to other causes such as transients, welding, and junction box/splices is about an order of magnitude less than cabinets. In fact, if this noncabinet frequency was used in the initial screening, these rooms would be close to being screened out at approximately 1E-6/yr. Because of this, it was decided to judgmentally consider a spatial reduction factor to completely screen these rooms. When considering the floor area where fires could potentially impact Div I cables (i.e., vertical trays or conduits near the floor) before suppression would occur, it was judged that 10% of the floor area could potentially cause some damage. Assuming that these fires are as likely to occur any place on the floor area, this would reduce core damage frequency to about 1E-7/yr. Note that this is conservative because it still assumes that for all these fires the worst case impacts also occur as in the initial screening analysis. A more realistic assessment could consider those areas

where both offsite power (loss of offsite power reduces the reliability of Div II) and Div I cables are located which would reduce the spatial reduction factor even further. Thus, identifying those areas where normal AC power and Div I can be impacted would produce a smaller spatial reduction factor. For those areas where a fire does not effect both offsite power and Div I, core damage frequency estimates for these scenarios would be much less. Finally, assuming that loss of Div I cables lead to a total loss of Div I equipment is still a conservatism in this analysis.

4.6.2.3.6 Reactor Building (FA34 212SW, 222SW, 232SW, 243SW & 252SW)

Similar to other locations, the total impacts associated with each zone were assumed to occur in the initial screening. The impacts include loss of Division I ECCS (RHR, LPCS, ADS), RCIC and balance of plant systems (RBCLC, main condenser, and feedwater). Each fire zone represents one half of a reactor building floor elevation which is a large area. The total frequency of a fire in FA34 is about 3.9E-2/yr. The initial screening analysis used a fire frequency of 1E-2/yr for each fire zone (assumed to be a reasonably conservative estimate) which led to a core damage frequency of 8E-6/yr for some zones. The reactor building was screened out by inspecting for the dominate (highest frequency) fire sources and the proximity of potential important targets during a walkdown. The strategy and walkdown notes are provided below.

Automatic cable tray water spray suppression is provided in each zone. The following summarizes the detectors in each fire zone:

Fire Zone	Number of Detectors	
	Temperature	Smoke
212SW	13	34
222SW	0	39
232SW	5	32
243SW	5	38
252SW	0	39

The frequency of a fire in FA34 is based on the following fire sources:

Source	Frequency (events/yr)
H2 Recombiner	2.9E-2
Pumps	6.4E-3
Elec Cabinet	2.1E-3
Compressors	5.9E-4
Ventilation/Fans	4.1E-4
Transformers	2.8E-4

JB/Splice	2.5E-4
Weld/ORD	2.0E-4
Weld/CAB	6.0E-5
Transients	4.1E-5

The initial screening analysis did not demonstrate that the fire zones meet the definition of a fire compartment in FIVE. However, core damage frequency results for the upper elevations screened out of the initial screening analysis and are not sensitive to the total fire frequency for area FA34. Also, given the size of these areas, height of the ceilings, and the floor openings, the accumulation of hot gases is difficult. During the walkdown, the proximity of cables to the ceiling and the potential for gas accumulation were considered and no important configurations or impacts were identified.

This fire area was evaluated utilizing the following strategy:

- Those fire sources with frequencies less than 1E-3 can be screened out. The total frequency of these other causes is on the order of 1E-3/yr; assuming the total impact as in the initial screening analysis, core damage frequency would be less than 1E-6/yr. However, during the walkdown, the proximity of compressors, ventilation/fans, and transformers to cables and other important systems were inspected to obtain confidence that fires from these sources can not have the impact assumed in the initial screening analysis. Also, junction boxes and splices (JB/Splice) are typically contained in enclosures without vents which means that these fires are expected to have only limited local impacts. This evaluation provides confidence that core damage frequency from these lower frequency sources is 1E-7/yr or less.

- Starting at elevation 175 (lowest elevation), each fire zone was inspected for the high frequency sources and their proximity to other important equipment and cables (i.e., radiant and plume impacts). Also, ceilings/overheads were visually inspected for the potential of hot gas accumulation and flow. During the walkdown, automatic cable tray water spray suppression capabilities were confirmed where important.

- When conduits or cable trays were found in close proximity to a source (<5 feet from electrical equipment), they were not considered important unless there is a mixture of safety (green and/or yellow) with nonsafety (black). If the fire does not impact both safety and nonsafety (balance of plant), the fire can be easily screened.

Each elevation was walked down with no distinction made between fire areas 34 and 35 (see Section 4.6.2.3.7). The impacts identified during the walkdown were evaluated (i.e., cable raceway database, CRS2, was used to identify cables within a raceway and the elementary and/or wiring diagrams used to identify impact). Based on impacts, fire frequency, and the IPE, FA34 was screened out.

4.6.2.3.7 Reactor Building (FA35 213SW, 223SW, 238SW, 245SW & 255SW)

This fire area is similar to FA34 described in the previous section. Similarly, the total impacts associated with each zone were assumed to occur in the initial screening. The impacts include loss of Division II ECCS (RHR, ADS), HPCS, and balance of plant systems (RBCLC, main condenser, and feedwater). Each fire zone represents one half of a reactor building floor elevation which is a large area. The total frequency of a fire in FA35 is about 3.8E-2/yr. The initial screening analysis used a fire frequency of 1E-2/yr for each fire zone (assumed to be a reasonably conservative estimate) which led to a core damage frequency of 8E-6/yr for some zones.

Automatic cable tray water spray suppression is provided in each zone. The following summarizes the detectors in each fire zone:

Fire Zone	Number of Detectors	
	Temperature	Smoke
213SW	20	35
223SW	0	39
238SW	1	32
245SW	2	37
255SW	4	33

The frequency of fires in FA35 is based on the following:

Source	Frequency (events/yr)
H2 Recombiner	2.9E-2
Pumps	4.1E-3
Elec Cabinet	2.1E-3
Elevator Motors	1.6E-3
Ventilation/Fans	5.3E-4
Transformers	5.7E-4
Compressors	3.9E-4
JB/Splice	2.2E-4
Weld/ORD	2.0E-4
Weld/CAB	6.0E-5
Transients	4.1E-5

The strategy for evaluating this fire area is the same as described in the previous section for FA34.

4.6.2.3.8 Service Water Pumps (FA60 807NZ & FA61 806NZ)

For each of these zones, the initial screening analysis assumed failure of the Division I service water header and pumps similar to the IPE initiator SAX (6.6E-4/yr with a CDF value of 3.2E-7/yr). A fire initiating event frequency in each zone equal to 6E-3/yr leads to a CDF value of about 3E-6/yr in each zone (symmetry between Div I and II is assumed). There are six smoke detectors provided for each fire zone with no automatic suppression.

A walkdown was performed to assess the location of fire sources that dominate the fire initiating event frequency to determine more realistic impacts of fires. It was noted prior to the walkdown that the fire frequency was dominated by electrical cabinets and pumps. The total frequency of other fire causes is about an order of magnitude less likely and a more detailed evaluation of these causes and impacts would likely result in additional reduction factors. Thus, their contribution to CDF is judged to be less than 1E-7/yr.

With regard to pump and electrical cabinet fires, the following summarizes the walkdown observations:

- The pumps are in a deep pit about forty feet below the deck (El 261) where most of the remaining service water equipment (strainers, MOVs, MCC, cable trays) is located. There is another elevation above the deck where hot gases would tend to collect given a fire in the area. There is no important equipment or cables at this higher elevation.

- There is sufficient distance between the three pumps, their associated cables, and other critical equipment on the upper deck such that a fire initiated at one pump is very unlikely to impact a second pump let alone all three as assumed in the screening analysis. The only conceivable scenario that could impact more than one pump might be a pump fire and oil spill onto the floor. However, there is limited oil associated with a pump motor and the surface area associated with oil spread on the floor to impact all three pumps is large. This may not even be credible, but if it is, the frequency of such an event is less than assumed in the screening analysis. In addition, the safety related header supplies are not impacted. Our judgment is that pump fires that impact all three pumps are unlikely and can be screened out (core damage frequency <1E-7/yr).

- There are two large unit coolers (e.g., 2HVY*UC2A & C in FA61) below the deck at El 261, but above one of the pumps. The initiating frequency for a unit cooler fire is less than the frequency for the pumps and the impact would likely be only one pump. Therefore, this source can be screened as stated above.

- The major electrical cabinet in each area is the MCC (e.g., 2EHS*MCC101 in FA61) on the deck at El 261. The MCC is actually contained within another cabinet, thus the impact of fires within the MCC are very unlikely to impact cable trays above the MCC. No vented cabinets that could impact cables or conduits were identified during the walkdown.

- Each MCC supplies Divisional strainers, strainer MOVs, pump discharge MOVs, unit coolers, a crosstie MOV, header MOVs and tunnel heaters. There are no cables that would depower the pumps and since service water is normally operating (MOVs are in their correct position for normal operation), a fire would have to cause a short circuit to have an impact on system operation (i.e., shorts cause pump discharge MOV or header MOV to close). The probability of a short is less than 1.0. In addition, the frequency of a fire that impacts more than one MCC cubicle causing loss of two or more pumps, or loss of pumps and header supplies is much less than the frequency used in the screening analysis. All these factors are judged to lead to core damage frequencies less than 1E-6/yr and probably <1E-7/yr if analyzed in further detail.

Based on the above analysis and walkdown observations, it is judged that core damage frequency in each area due to fires is easily <1E-6/yr and probably <1E-7/yr.

4.6.2.3.9 Division II Cable Chases (FA18 304NW, 324NW, 337NW, 359NW, 377NW & FA19 323NW)

The initial screening analysis assumed failure of Division II AC power and HPCS, given a fire in one of these locations. This was based on the Appendix R analysis which indicated that Division II and HPCS are impacted. The actual impact on Division II was not assessed. In addition, the BOP cable evaluation identified a partial loss of offsite power and other balance of plant systems being lost. The following summarizes detection and suppression in each zone:

Fire Zone	Number of Detectors		Type of Automatic Fire Suppression	
	Temp	Smoke	Area Water Sprinkler	Cable Tray Water Spray
304NW	0	4	Yes	Yes
324NW	0	4	Yes	Yes
337NW	0	5	No	Yes
359NW	0	5	Yes	Yes
377NW	0	3	Yes	Yes
323NW	0	15	No	Yes

These areas are similar to the Division I Cable Chase West areas described in Section 4.6.2.3.5. However, the frequency of core damage is less for these Division II areas (approximately 3E-6/yr for each area) which means that smaller reduction factors are needed to screen these areas. Rather than document impacts of cabinets in detail, as done in Table 4.6-5 for the Division I areas, a walkdown and review was performed to assure that cabinet impacts are similar to those in the Division I areas (i.e., symmetry) and to investigate the proximity of vented cabinets to cable trays and conduits. Note that 337NW, 359NW and

337NW are symmetrical to those Division I zones described in Section 4.6.2.3.5. There were very few cabinets in the other zones. Based on this review, it was concluded that the approach taken for the Division I areas also applied in these areas as summarized below:

- Taking credit for automatic suppression (0.05 unavailability assumed) in these rooms would result in a core damage frequency less than 1E-6/yr still assuming the worst impact as in the initial screening analysis. Note that only IEEE 383 cables are used and for most fires it is not expected that impacts would occur away from the fire (i.e., hot gas layers, etc) even without suppression (i.e. fire burns out).

- The configuration of zones 337NW, 359NW and 337NW is similar to the Division I zones evaluated in Section 4.6.2.3.5 and the impact of cabinet fires is similarly symmetrical. No significant new scenario was identified from the walkdown and review of cabinets. Thus,. these zones can be screened out for the same reasons developed in Section 4.6.2.3.5.

Thus, fire zones 304NW, 323NW and 324NW can also be screened for the same reasons developed in Section 4.6.2.3.5.

4.6.2.3.10 Remote Shutdown Room B East (FA19 338NZ)

The initial screening analysis conservatively assumed that Division II AC power was impacted by a fire in this zone. Since the actual impact was not evaluated, this was performed first.

The remote shutdown panel 2CES*PNL405 contains both remote shutdown divisions that are separated by a three hour fire wall. This panel contains transfer switches and controls. Panels 2CES*PNL415 & 2CES*PNL416 are not located within the remote shutdown room. They contain isolation switches that prevents spurious operation where needed and it provides isolation for circuits that need manual actuation for remote safe shutdown. The design bases for these switches assumes that the switches are transferred before their circuits are impacted by the control room fire. A fire at either panel causes loss of all circuits connected to the panel. For the control room fire, two switches at 2CES*PNL415 or 416 and at the remote shutdown panel must be thrown to recover a service water pump. The 2CES*PNL415/416 switches isolates unwanted control room contacts and the transfer switch isolates the operation features.

A fire at the remote shutdown panel could cause loss of Divisional service water (the three Divisional pumps trip and/or lose control power). These pumps cannot be operated from the control room. Additionally, the fire can cause actuation of an SRV (1 or more of 4 SRVs). Loss of control power to one solenoid is not a concern because the SRVs have three solenoids (two from Division I and one from Division II that can actuate the valve). There is a possibility that these valves cannot be closed if they spuriously open. A RHR pump can be lost due failure of control cables.

Diesel generator backed AC power is not directly impacted by a fire in 2CES*PNL405. AC power components are isolated by either 2CES*PNL415 or 2CES*PNL416, both located in different fire areas from the remote shutdown panel.

Two smoke detectors are provided with no automatic suppression. This is a small room with the impacts concentrated at one panel. For this reason no credit for suppression before impact was considered. A fire initiator (FA338 = 1.5E-4/yr) was run through the IPE model as follows:

Loss of Division II service water pumps was modeled with the following rules:

SAF	INIT=FA338*(A1=F+D1=F+KA=F)
SAH	INIT=FA338
SBF	INIT=FA338

Loss of RCIC (added INIT=FA338 to ICF) due to ADS actuation
ADS success (SVS and ODS given INIT=FA338)
Loss of RHR (added INIT=FA338 to LBF)

The resulting core damage frequency from FA338 is less than 1E-7/yr.

The above calculation is conservative because KA=F does not necessarily fail SA and SB can be successful when SA either succeeds or fails. ADS actuation requires hot shorts with a probability which was not applied (i.e., 0.1). Allowing RCIC to succeed and requiring the operators to actuate ADS would lead to a core damage frequency estimate comparable to or less than calculated for the above case.

4.6.2.3.11 Operators Lunch Room El 306 (FA76 380.1NZ)

This fire zone was not evaluated at all during the initial screening analysis. The initial screening analysis assumed loss of Division I AC power and HPCS based on Appendix R results and because the spatial database developed for fire area 76 did not distinguish between zones 380.1NZ (operators lunch room) and 380.2NZ (corridor). Thus, the actual cables being routed in these zones have to be evaluated. There are smoke detectors in the area with no automatic suppression. However, there are operators and other personnel either in the area or close by.

During a walkdown, the following conduits were observed on one wall in the room:

- 2CC502PF1 (purple), 2CC502PF2 (purple), 2CC502PF4 (purple), 2CC502PF5 (purple)

- 2CC520YP (yellow) containing cable 2HVKBYC503

The purple cables are associated with the HPCS (Div III) system and the yellow cable is associated with Div II chilled water (control building cooling). Even if failure of these cables is assumed, the impact would be insignificant and this location can be screened out as <1E-6/yr (probably much less than 1E-6 because this would not be an initiating event in the IPE). There are smoke detectors in this area with no automatic suppression.

4.6.2.3.12 Division I Standby Switchgear Room (FA17 333XL)

The initial screening analysis assumed that Division I AC power and RCIC failed, given a fire in this location. The functional design of the electrical distribution system for Division I is essentially identical to the Division II functional design (see Section 4.6.2.3.4). Walkdowns and design reviews were performed to compare this area with the Division II room in Section 4.6.2.3.4. The ceiling and cables in this room are very high. Cables enter the cabinets from the top as well as from underneath. There are 7 smoke detectors in this fire zone and an automatic carbon dioxide total flooding suppression system. The Division I and II standby switchgear rooms each have the same number of cabinets with the same ratio of empty to de-energized cubicles. The relative locations of protective relay cabinets are essentially the same. There are some differences in the physical routing of conduits and raceways. The degree of separation or independence of cables associated with the offsite power sources and those associated with the diesel was evaluated to determine the number of locations where a fire can cause the loss of both offsite power and the failure of the diesel. There are no cable trays over the Division I 125 VDC switchgear as there is in the Division II standby switchgear room and no RBCLC system cables.

Core damage frequency from the initial screening analysis is about 2E-6/yr which is close to the screening criteria. This value is also about an order of magnitude less than the Division II switchgear screening analysis which was subsequently screened in Section 4.6.2.3.4. Because these switchgear rooms are very similar with regard to design, cabinets, routing of normal AC and diesel cables, and fire impacts, this section does not provide the same level of detail as in Section 4.6.2.3.4. Instead, the important attributes identified in Section 4.6.2.3.4 that reduce the probability of core damage were checked by design review and walkdown. These important attributes include the fact that fire frequency is dominated by electrical cabinets, that normal AC power and diesel supply cables are separated such that failure of both is dominated by cabinet fires in specific cubicles, that the switchgear is similar to the Division II switchgear, and the room arrangements and configurations are very similar. Based on this review, the area easily screens below 1E-7/yr.

4.6.2.3.13 Normal Switchgear Rooms (FA51 601XL, FA52 602XL, FA78 612XL & FA79 613XL)

The initial screening analysis assumed that normal offsite power and balance of plant systems failed, given a fire in this location. Each of these areas was close to the initial screening analysis value for core damage frequency with values ranging from 1.1E-6/yr to 1.3E-6/yr. The frequency of fires is dominated by electrical cabinet fires similar to other areas evaluated previously. With the exception of FA52 which has MG sets that contribute, electrical cabinets dominate by an order of magnitude. Thus, the screening of these areas concentrated on electrical cabinets and the MG sets similar to other analyses (i.e., Section 4.6.2.3.4). Each fire zone has smoke detectors and an automatic actuated total flooding carbon dioxide suppression system. The fraction of fires that cause a total loss of offsite power versus partial loss of offsite power or even less impacts is the key to this analysis. Fires that cause a partial loss of offsite power would screen out at 1E-7/yr or less.

Based on the above and previous analysis, walkdowns and design reviews were performed to develop confidence that a reduction factor of at least 1/10 could be developed for cabinet fires that cause total loss of offsite power. No single cabinet was identified that could cause a total loss of offsite power. Cable trays were identified that could lead to total loss of offsite power, however, the automatic suppression system provides confidence that propagation and damage to cable trays is unlikely. The following summarizes walkdown and design review conclusions:

- FA51 - This fire area contains the chargers and switchgear that is associated with the 125 VDC systems 2BYS-SWG001A and 2BYS-SWG001B. The power cables for 2NNS-SWG016 are routed through this area. There are numerous cables associated with the 115KV motorized disconnects. A fire in this area results in the loss of offsite power to 2ENS*SWG101 due to cables - cabinet fires do not fail offsite power supplies. Loss of balance of plant systems should be assumed since this was not evaluated.

- FA52 - A fire in this area can result in a total loss of offsite power due to control cables - cabinet fires do not fail offsite power supplies. Power cables to both 2NNS-SWG016 and 017 are routed in this area, there is approximately 50 feet separation between the cables (cables to SWG016 are routed on the opposite end of the room from SWG017 cables). Loss of balance of plant systems should be assumed since this was not evaluated.

  This area contains the grounding transformers for the main supply transformers from offsite power, the feeder cables for buses 2NNS-SWG016, 017, the motor generator sets for the RPS power, two nonsafety UPSs, UPS3A & B, the grounding transformers for the 4.16 KV busses 2NNS-SWG016, 2NNS-SWG017, 2NNS-SWG018 and the four nonsafety UPSs, UPS1A,B,C,D.

  Loss of a grounding transformers, by itself, will not result in loss of offsite power to the associated bus. The AC power system for this bus is delta connected and is not grounded. For a fire to cause the loss of the associated offsite power bus, another concurrent failure in a power feed must occur in addition to a fault in the grounding transformer power cable.

  Loss of the RPS UPSs 2VBB-UPS3A & 3B will result in a reactor trip and vessel isolation. There are a few cables 15 ft directly above the UPSs. At higher elevations there are more cables.

Loss of the BOP UPSs is conservatively assumed to result in loss of the BOP systems.

The offsite power cables supplying power to both Division I & II 4Kv busses pass through this room. There is approximately 50 feet separation between these power cables at the point of closest approach. The intervening space between the tray routes has a small combustible loading, consisting of horizontal cable trays.

The control cables for the motorized disconnects in the 115 KV switchyard are impacted by a fire that affects either trays 2TC850N or 2TC855N. If the fire causes wire to wire short circuits then the motorized disconnects will open and not be able to be reclosed. A minimum of two disconnects opening (2YUC-MDS3 or 2YUL-MDS1 and 2YUC-MDS4 or 2YUL-MDS2) isolate the plant from offsite power. In this case offsite power is not recoverable.

- FA78 - A fire in this area can result in a total loss of offsite power due to control cables - cabinet fires can cause a partial loss of offsite power (loss of 2NNS-SWG016 supply). Loss of balance of plant systems should be assumed since this was not evaluated.

- FA79 - A fire in this area can result in a total loss of offsite power due to control cables - cabinet fires can cause a partial loss of offsite power (loss of 2NNS-SWG017 supply). Loss of balance of plant systems should be assumed since this was not evaluated.

Figure 4.6-1 - Control Room Fire 1 (panel 852)

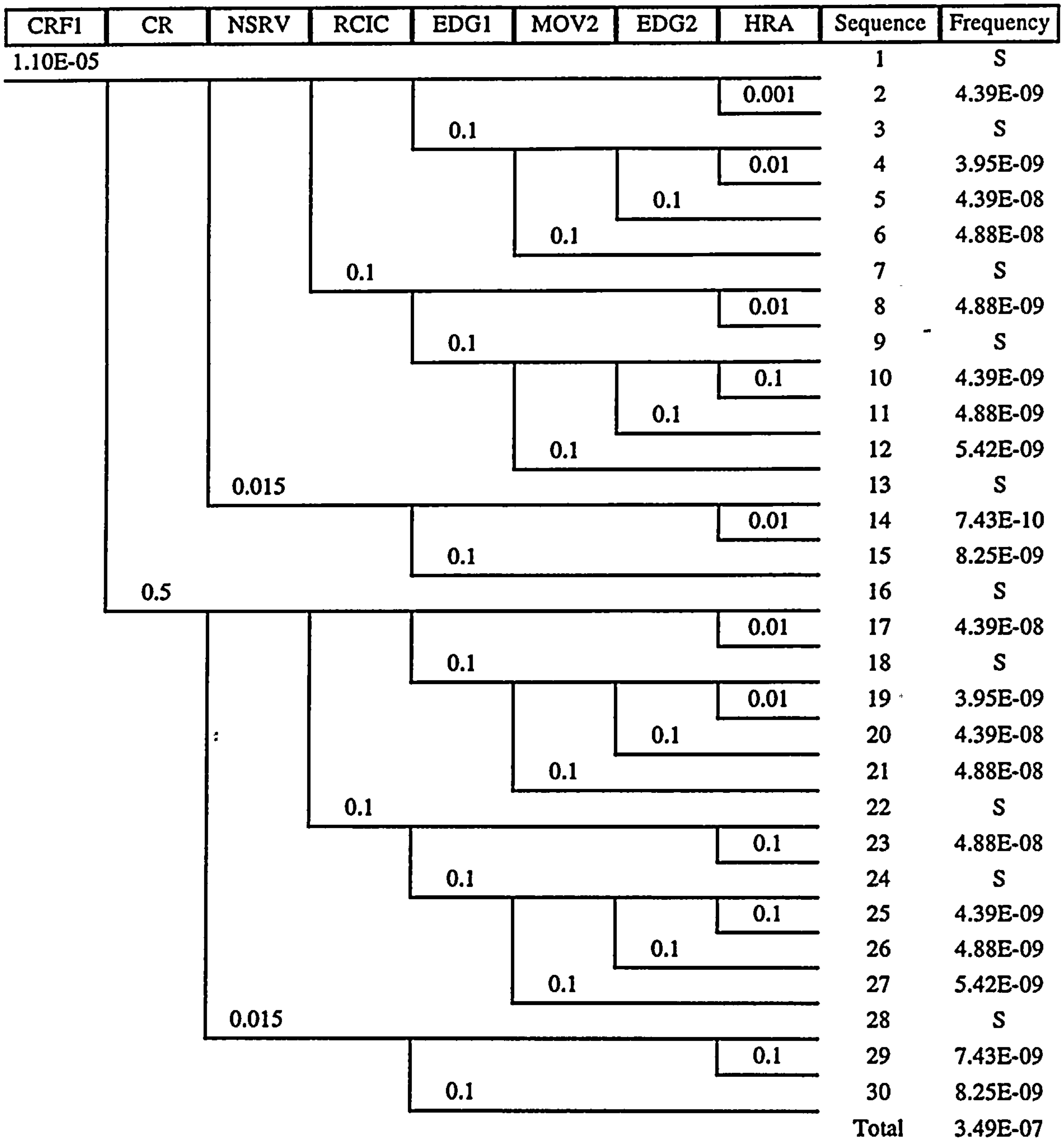


Figure 4.6-1 - Control Room Fire 1 (panel 852)

Top Event	Description
CR	Operators initially decide to stay in the control room and fire conditions allow this
NSRV	No stuck open SRV as a result of the plant transient
RCIC	RCIC is available and operates for 24 hours
EDG1	Division I EDG is available and operates for 24 hours
MOV2	Division II EDG service water MOV does not fail closed prior to loss of offsite power
EDG2	Division II EDG is available and operates for 24 hours
HRA	Depending on sequence, operators stabilize and/or recover plant maintaining RPV level and heat removal.

Figure 4.6-2 - Control Room Fire 2 (panel 852)

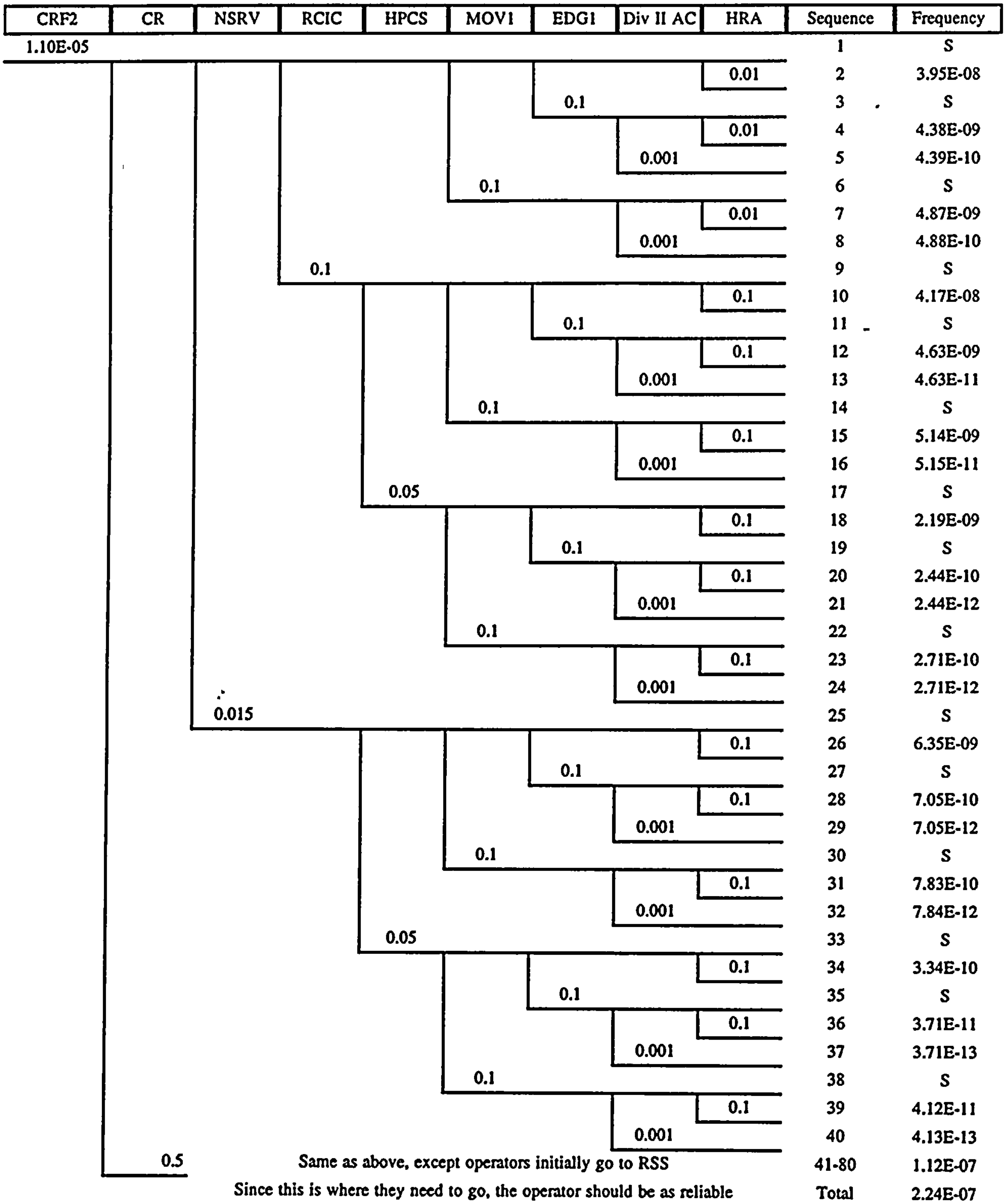
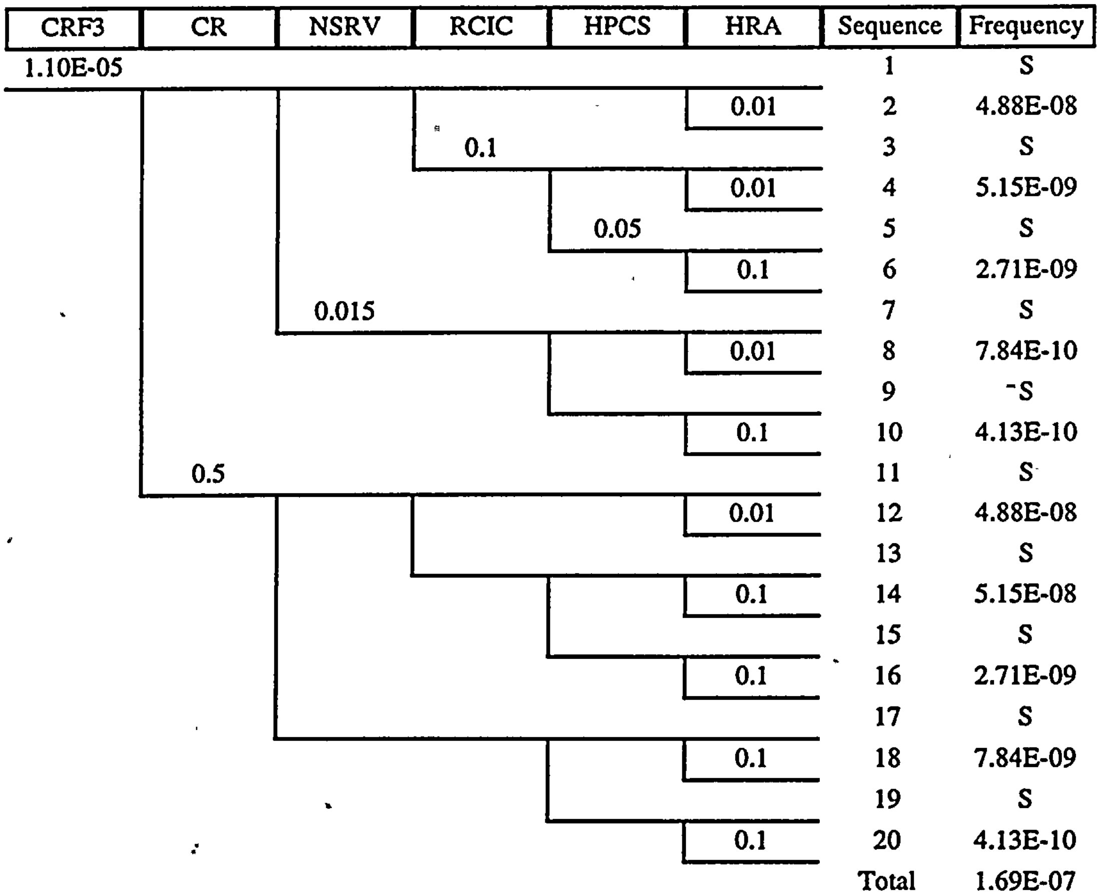


Figure 4.6-2 - Control Room Fire 1 (panel 852)

Top Event	Description
CR	Operators initially decide to stay in the control room and fire conditions allow this
NSRV	No stuck open SRV as a result of the plant transient
RCIC	RCIC is available and operates for 24 hours
HPCS	HPCS is available and operates for 24 hours
MOV1	Division I EDG service water MOV does not fail closed prior to loss of offsite power
EDG1	Division I EDG is available and operates for 24 hours
Div II AC	Division AC switchgear is available and operates for 24 hours (EDG not required)
HRA	Depending on sequence, operators stabilize and/or recover plant maintaining RPV level and heat removal.

Figure 4.6-3 - Control Room Fire 3 (panel 601)



Top Event	Description
CR	Operators initially decide to stay in the control room and fire conditions allow this
NSRV	No stuck open SRV as a result of the plant transient
RCIC	RCIC is available and operates for 24 hours
HPCS	HPCS is available and operates for 24 hours
HRA	Depending on sequence, operators stabilize and/or recover plant maintaining RPV level and heat removal.

Table 4.6-1 LOSP Cable Database With Locations and Impacts on IPE							
FA	FZONE	Impact	RACEWAY	CBL	System	Component	Affect
FA16	321NW	KAR	2CC523GG	2ENSXGC316	KA	2ENS*SWG101	T, FAI
FA16	321NW	KAR	2CC523GG	2ENSXGC319	KA	2ENS*SWG101	T, FAI
FA16	321NW	KAR	2CK521GJ	2ENSXGC319	KA	2ENS*SWG101	T, FAI
FA16	321NW	KAR	2CK521GK	2ENSXGC316	KA	2ENS*SWG101	T, FAI
FA16	321NW	KAR	2TC521G	2ENSXGC312	KA	2ENS*SWG101	T, FAI
FA16	321NW	KAR	2TC522G	2ENSXGC312	KA	2ENS*SWG101	T, FAI
FA16	321NW	KAR	2TC523G	2ENSXGC316	KA	2ENS*SWG101	T, FAI
FA16	321NW	KAR	2TC523G	2ENSXGC319	KA	2ENS*SWG101	T, FAI
FA16	321NW	KAR	2TC525G	2ENSXGC302	KA	2ENS*SWG101	T, FAI
FA16	321NW	KAR	2TC526G	2ENSXGC302	KA	2ENS*SWG101	T, FAI
FA16	321NW	KAR	2TK555G	2ENSXGC302	KA	2ENS*SWG101	T, FAI
FA16	332NW	KAR	2CK521GA	2ENSXGC312	KA	2ENS*SWG101	T, FAI
FA16	332NW	KAR	2CK521GJ	2ENSXGC319	KA	2ENS*SWG101	T, FAI
FA16	332NW	KAR	2CK521GK	2ENSXGC316	KA	2ENS*SWG101	T, FAI
FA16	332NW	KA	2TC505N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA16	332NW	KA	2TC505N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA16	332NW	KA	2TC508N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA16	332NW	KR	2TC508N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA16	332NW	KB	2TC508N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA16	332NW	KR	2TC508N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA16	332NW	KA	2TC508N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA16	332NW	KA	2TC508N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA16	332NW	KAR	2TC510N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA16	332NW	KBR	2TC510N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA16	332NW	KA	2TC514N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA16	332NW	KR	2TC514N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA16	332NW	KB	2TC514N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA16	332NW	KR	2TC514N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA16	332NW	KA	2TC514N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA16	332NW	KA	2TC514N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA16	332NW	KAR	2TC516N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA16	332NW	KBR	2TC516N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA16	332NW	KA	2TC607N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA16	332NW	KA	2TC607N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA16	332NW	KA	2TC610N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA16	332NW	KR	2TC610N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA16	332NW	KB	2TC610N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA16	332NW	KR	2TC610N	2SPFYNC615	KR	2YUC-MDS20	T, FAI

Table 4.6-1 LOSP Cable Database With Locations and Impacts on IPE							
FA	FZONE	Impact	RACEWAY	CBL	System	Component	Affect
FA16	332NW	KAR	2TC612N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA16	332NW	KBR	2TC612N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA16	332NW	KA	2TC613N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA16	332NW	KA	2TC613N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA16	332NW	KA	2TC616N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA16	332NW	KR	2TC616N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA16	332NW	KB	2TC616N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA16	332NW	KR	2TC616N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA16	332NW	KAR	2TC618N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA16	332NW	KBR	2TC618N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA16	332NW	KA	2TC619N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA16	332NW	KA	2TC619N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA16	332NW	KA	2TC622N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA16	332NW	KR	2TC622N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA16	332NW	KB	2TC622N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA16	332NW	KR	2TC622N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA16	332NW	KAR	2TC624N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA16	332NW	KBR	2TC624N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA16	332NW	KA	2TC631N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA16	332NW	KA	2TC631N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA16	332NW	KA	2TC634N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA16	332NW	KR	2TC634N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA16	332NW	KB	2TC634N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA16	332NW	KR	2TC634N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA16	332NW	KAR	2TC636N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA16	332NW	KBR	2TC636N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA16	332NW	KA	2TK527N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA16	332NW	KA	2TK527N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA16	332NW	KAR	2TK534N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA16	332NW	KBR	2TK534N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA16	332NW	KA	2TK547N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA16	332NW	KR	2TK547N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA16	332NW	KB	2TK547N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA16	332NW	KR	2TK547N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA16	332NW	KAR	2TK556G	2ENSXGC302	KA	2ENS*SWG101	T, FAI
FA16	332NW	KA	2TK613N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA16	332NW	KA	2TK613N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA16	352NW	KAR	2TC548G	2ENSXGC302	KA	2ENS*SWG101	T, FAI

Table 4.6-1 LOSP Cable Database With Locations and Impacts on IPE							
FA	FZONE	Impact	RACEWAY	CBL	System	Component	Affect
FA16	352NW	KAR	2TC549G	2ENSXGC302	KA	2ENS*SWG101	T, FAI
FA16	352NW	KA	2TK528N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA16	352NW	KA	2TK528N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA16	352NW	KAR	2TK535N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA16	352NW	KBR	2TK535N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA16	352NW	KA	2TK548N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA16	352NW	KR	2TK548N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA16	352NW	KB	2TK548N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA16	352NW	KR	2TK548N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA16	352NW	KAR	2TK557G	2ENSXGC302	KA	2ENS*SWG101	T, FAI
FA16	352NW	KAR	2TK563G	2ENSXGC302	KA	2ENS*SWG101	T, FAI
FA16	371NW	KAR	2TC662N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA16	371NW	KBR	2TC662N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA16	371NW	KAR	2TC663N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA16	371NW	KBR	2TC663N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA16	371NW	KAR	2TC664N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA16	371NW	KBR	2TC664N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA16	371NW	KAR	2TC665N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA16	371NW	KBR	2TC665N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA16	371NW	KAR	2TC666N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA16	371NW	KBR	2TC666N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA16	371NW	KAR	2TC667N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA16	371NW	KBR	2TC667N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA16	371NW	KA	2TK515N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA16	371NW	KR	2TK515N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA16	371NW	KB	2TK515N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA16	371NW	KR	2TK515N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA16	371NW	KA	2TK516N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA16	371NW	KR	2TK516N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA16	371NW	KB	2TK516N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA16	371NW	KR	2TK516N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA16	371NW	KA	2TK517N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA16	371NW	KR	2TK517N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA16	371NW	KB	2TK517N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA16	371NW	KR	2TK517N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA16	371NW	KA	2TK518N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA16	371NW	KR	2TK518N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA16	371NW	KB	2TK518N	2SPFYNC614	KB	2YUL-MDS2	T, FAI

Table 4.6-1 LOSP Cable Database With Locations and Impacts on IPE							
FA	FZONE	Impact	RACEWAY	CBL	System	Component	Affect
FA16	371NW	KR	2TK518N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA16	371NW	KA	2TK519N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA16	371NW	KR	2TK519N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA16	371NW	KB	2TK519N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA16	371NW	KR	2TK519N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA16	371NW	KAR	2TK536N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA16	371NW	KBR	2TK536N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA16	371NW	KA	2TK549N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA16	371NW	KR	2TK549N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA16	371NW	KB	2TK549N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA16	371NW	KR	2TK549N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA16	371NW	KAR	2TK564G	2ENSXGC302	KA	2ENS*SWG101	T, FAI
FA16	371NW	KA	2TK609N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA16	371NW	KR	2TK609N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA16	371NW	KB	2TK609N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA16	371NW	KR	2TK609N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA16	371NW	KAR	2TK612N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA16	371NW	KBR	2TK612N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA17	322NW	KAR	2CC514GD	2ENSXGC304	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2CC514GD	2ENSXGC319	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2CC514GE	2ENSXGC312	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2CC514GE	2ENSXGC316	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2CC529GB	2ENSXGC302	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2TC511G	2ENSXGC316	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2TC511G	2ENSXGC319	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2TC512G	2ENSXGC316	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2TC512G	2ENSXGC319	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2TC513G	2ENSXGC316	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2TC513G	2ENSXGC319	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2TC514G	2ENSXGC304	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2TC514G	2ENSXGC312	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2TC514G	2ENSXGC316	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2TC514G	2ENSXGC319	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2TC515G	2ENSXGC304	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2TC515G	2ENSXGC312	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2TC527G	2ENSXGC302	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2TC528G	2ENSXGC302	KA	2ENS*SWG101	T, FAI
FA17	322NW	KAR	2TC529G	2ENSXGC302	KA	2ENS*SWG101	T, FAI

Table 4.6-1 LOSP Cable Database With Locations and Impacts on IPE							
FA	FZONE	Impact	RACEWAY	CBL	System	Component	Affect
FA17	325NW	KAR	2CC518GF	2ENSXGC304	KA	2ENS*SWG101	T, FAI
FA17	325NW	KAR	2TC517G	2ENSXGC304	KA	2ENS*SWG101	T, FAI
FA17	325NW	KAR	2TC518G	2ENSXGC304	KA	2ENS*SWG101	T, FAI
FA17	333XL	KAR	2CH505ND	2NNSXNH303	KA	2NNS-SWG016	F
FA17	333XL	KAR	2CH505NE	2NNSXNH302	KA	2NNS-SWG016	F
FA17	333XL	KAR	2CH505NF	2NNSXNH301	KA	2NNS-SWG016	F
FA17	333XL	KAR	2TH505N	2NNSXNH301	KA	2NNS-SWG016	F
FA17	333XL	KAR	2TH505N	2NNSXNH302	KA	2NNS-SWG016	F
FA17	333XL	KAR	2TH505N	2NNSXNH303	KA	2NNS-SWG016	F
FA18	324NW	KBR	2TC538Y	2ENSYYC302	KB	2ENS*SWG103	T, FAI
FA18	324NW	KBR	2TC538Y	2ENSYYC312	KB	2ENS*SWG103	T, FAI
FA18	324NW	KBR	2TC538Y	2ENSYYC316	KB	2ENS*SWG103	T, FAI
FA18	324NW	KBR	2TC538Y	2ENSYYC319	KB	2ENS*SWG103	T, FAI
FA18	324NW	KBR	2TC539Y	2ENSYYC302	KB	2ENS*SWG103	T, FAI
FA18	324NW	KBR	2TC539Y	2ENSYYC312	KB	2ENS*SWG103	T, FAI
FA18	324NW	KBR	2TC539Y	2ENSYYC316	KB	2ENS*SWG103	T, FAI
FA18	324NW	KBR	2TC539Y	2ENSYYC319	KB	2ENS*SWG103	T, FAI
FA18	324NW	KBR	2TK554Y	2ENSYYC302	KB	2ENS*SWG103	T, FAI
FA18	337NW	KB	2TC532N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA18	337NW	KR	2TC532N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA18	337NW	KB	2TC561N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA18	337NW	KR	2TC561N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA18	337NW	KB	2TC580N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA18	337NW	KR	2TC580N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA18	337NW	KB	2TC586N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA18	337NW	KR	2TC586N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA18	337NW	KB	2TC592N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA18	337NW	KR	2TC592N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA18	337NW	KBR	2TK555Y	2ENSYYC302	KB	2ENS*SWG103	T, FAI
FA18	337NW	KB	2TK631N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA18	337NW	KR	2TK631N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA18	359NW	KBR	2TK556Y	2ENSYYC302	KB	2ENS*SWG103	T, FAI
FA18	359NW	KB	2TK632N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA18	359NW	KR	2TK632N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA18	377NW	KBR	2TK557Y	2ENSYYC302	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2CC515YA	2ENSYYC304	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2CC534YA	2ENSYYC302	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2CC534YA	2ENSYYC312	KB	2ENS*SWG103	T, FAI

Table 4.6-1 LOSP Cable Database With Locations and Impacts on IPE							
FA	FZONE	Impact	RACEWAY	CBL	System	Component	Affect
FA19	323NW	KBR	2CC534YA	2ENSYYC316	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2CC534YA	2ENSYYC319	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC515Y	2ENSYYC304	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC516Y	2ENSYYC304	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC517Y	2ENSYYC304	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC518Y	2ENSYYC304	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC534Y	2ENSYYC302	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC534Y	2ENSYYC312	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC534Y	2ENSYYC316	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC534Y	2ENSYYC319	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC535Y	2ENSYYC302	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC535Y	2ENSYYC312	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC535Y	2ENSYYC316	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC535Y	2ENSYYC319	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC536Y	2ENSYYC302	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC536Y	2ENSYYC312	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC536Y	2ENSYYC316	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC536Y	2ENSYYC319	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC537Y	2ENSYYC302	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC537Y	2ENSYYC312	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC537Y	2ENSYYC316	KB	2ENS*SWG103	T, FAI
FA19	323NW	KBR	2TC537Y	2ENSYYC319	KB	2ENS*SWG103	T, FAI
FA19	326NW	KBR	2CC521YF	2ENSYYC304	KB	2ENS*SWG103	T, FAI
FA19	326NW	KBR	2TC520Y	2ENSYYC304	KB	2ENS*SWG103	T, FAI
FA19	326NW	KBR	2TC521Y	2ENSYYC304	KB	2ENS*SWG103	T, FAI
FA19	336XL	KBR	2CH513NB	2NNSYNH302	KB	2NNS-SWG017	F
FA19	336XL	KBR	2CH513NC	2NNSYNH303	KB	2NNS-SWG017	F
FA19	336XL	KB	2TC561N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA19	336XL	KR	2TC561N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA19	336XL	KBR	2TH513N	2NNSYNH302	KB	2NNS-SWG017	F
FA19	336XL	KBR	2TH513N	2NNSYNH303	KB	2NNS-SWG017	F
FA51	601XL	KR	2CK855NB	2SPFXNK601	KR	2YUC-MDS10	FAI
FA51	601XL	KBR	2CK855NE	2NNSANK604	KB	2NNS-SWG017	FAI
FA51	601XL	KA	2CK856NF	2SPFXNK600	KA	2YUL-MDS1	FAI
FA51	601XL	KR	2CK873NB	2SPFYNK601	KR	2YUC-MDS20	FAI
FA51	601XL	KBR	2CK873NE	2NNSBNK604	KB	2NNS-SWG017	FAI
FA51	601XL	KB	2CK873NF	2SPFYNK600	KB	2YUL-MDS2	FAI
FA51	601XL	KA	2TC860N	2SPFXNC614	KA	2YUL-MDS1	T, FAI

Table 4.6-1 LOSP Cable Database With Locations and Impacts on IPE							
FA	FZONE	Impact	RACEWAY	CBL	System	Component	Affect
FA51	601XL	KR	2TC860N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA51	601XL	KA	2TC860N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA51	601XL	KA	2TC860N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA51	601XL	KR	2TC860N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA51	601XL	KAR	2TH886N	2NNSXNH301	KA	2NNS-SWG016	F
FA51	601XL	KAR	2TH886N	2NNSXNH302	KA	2NNS-SWG016	F
FA51	601XL	KAR	2TH886N	2NNSXNH303	KA	2NNS-SWG016	F
FA51	601XL	KAR	2TH887N	2NNSXNH301	KA	2NNS-SWG016	F
FA51	601XL	KAR	2TH887N	2NNSXNH302	KA	2NNS-SWG016	F
FA51	601XL	KAR	2TH887N	2NNSXNH303	KA	2NNS-SWG016	F
FA51	601XL	KBR	2TK855N	2NNSANK604	KB	2NNS-SWG017	FAI
FA51	601XL	KR	2TK855N	2SPFXNK601	KR	2YUC-MDS10	FAI
FA51	601XL	KBR	2TK856N	2NNSANK604	KB	2NNS-SWG017	FAI
FA51	601XL	KA	2TK856N	2SPFXNK600	KA	2YUL-MDS1	FAI
FA51	601XL	KR	2TK856N	2SPFXNK601	KR	2YUC-MDS10	FAI
FA51	601XL	KA	2TK872N	2SPFXNK600	KA	2YUL-MDS1	FAI
FA51	601XL	KR	2TK872N	2SPFXNK601	KR	2YUC-MDS10	FAI
FA51	601XL	KR	2TK872N	2SPFYNK601	KR	2YUC-MDS20	FAI
FA51	601XL	KBR	2TK873N	2NNSBNK604	KB	2NNS-SWG017	FAI
FA51	601XL	KB	2TK873N	2SPFYNK600	KB	2YUL-MDS2	FAI
FA51	601XL	KR	2TK873N	2SPFYNK601	KR	2YUC-MDS20	FAI
FA51	601XL	KBR	2TK874N	2NNSBNK604	KB	2NNS-SWG017	FAI
FA51	601XL	KB	2TK874N	2SPFYNK600	KB	2YUL-MDS2	FAI
FA51	601XL	KBR	2TK875N	2NNSBNK604	KB	2NNS-SWG017	FAI
FA51	601XL	KB	2TK875N	2SPFYNK600	KB	2YUL-MDS2	FAI
FA52	602XL	KB	2CC852NH	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA52	602XL	KR	2CC852NH	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA52	602XL	KB	2CC852NH	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA52	602XL	KBR	2CH880NB	2NNSYNH302	KB	2NNS-SWG017	F
FA52	602XL	KBR	2CH880NC	2NNSYNH303	KB	2NNS-SWG017	F
FA52	602XL	KB	2CK866NF	2SPFYNK600	KB	2YUL-MDS2	FAI
FA52	602XL	KR	2CK866NF	2SPFYNK601	KR	2YUC-MDS20	FAI
FA52	602XL	KA	2TC850N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA52	602XL	KR	2TC850N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA52	602XL	KB	2TC850N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA52	602XL	KR	2TC850N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA52	602XL	KA	2TC850N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA52	602XL	KA	2TC850N	2YUCXNC308	KA	2YUS-MDS3	T, FAI

Table 4.6-1 LOSP Cable Database With Locations and Impacts on IPE							
FA	FZONE	Impact	RACEWAY	CBL	System	Component	Affect
FA52	602XL	KB	2TC850N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA52	602XL	KR	2TC850N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA52	602XL	KB	2TC852N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA52	602XL	KR	2TC852N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA52	602XL	KB	2TC852N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA52	602XL	KR	2TC852N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA52	602XL	KA	2TC855N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA52	602XL	KR	2TC855N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA52	602XL	KB	2TC855N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA52	602XL	KR	2TC855N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA52	602XL	KA	2TC855N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA52	602XL	KA	2TC855N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA52	602XL	KB	2TC855N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA52	602XL	KR	2TC855N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA52	602XL	KA	2TC860N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA52	602XL	KR	2TC860N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA52	602XL	KA	2TC860N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA52	602XL	KA	2TC860N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA52	602XL	KR	2TC860N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA52	602XL	KBR	2TH857N	2NNSYNH302	KB	2NNS-SWG017	F
FA52	602XL	KBR	2TH857N	2NNSYNH303	KB	2NNS-SWG017	F
FA52	602XL	KAR	2TH860N	2NNSXNH301	KA	2NNS-SWG016	F
FA52	602XL	KAR	2TH860N	2NNSXNH302	KA	2NNS-SWG016	F
FA52	602XL	KAR	2TH860N	2NNSXNH303	KA	2NNS-SWG016	F
FA52	602XL	KBR	2TH880N	2NNSYNH302	KB	2NNS-SWG017	F
FA52	602XL	KBR	2TH880N	2NNSYNH303	KB	2NNS-SWG017	F
FA52	602XL	KBR	2TH881N	2NNSYNH302	KB	2NNS-SWG017	F
FA52	602XL	KBR	2TH881N	2NNSYNH303	KB	2NNS-SWG017	F
FA52	602XL	KBR	2TH882N	2NNSYNH302	KB	2NNS-SWG017	F
FA52	602XL	KBR	2TH882N	2NNSYNH303	KB	2NNS-SWG017	F
FA52	602XL	KBR	2TH883N	2NNSYNH302	KB	2NNS-SWG017	F
FA52	602XL	KBR	2TH883N	2NNSYNH303	KB	2NNS-SWG017	F
FA52	602XL	KBR	2TH884N	2NNSYNH302	KB	2NNS-SWG017	F
FA52	602XL	KBR	2TH884N	2NNSYNH303	KB	2NNS-SWG017	F
FA52	602XL	KAR	2TH887N	2NNSXNH301	KA	2NNS-SWG016	F
FA52	602XL	KAR	2TH887N	2NNSXNH302	KA	2NNS-SWG016	F
FA52	602XL	KAR	2TH887N	2NNSXNH303	KA	2NNS-SWG016	F
FA52	602XL	KAR	2TH888N	2NNSXNH301	KA	2NNS-SWG016	F

Table 4.6-1 LOSP Cable Database With Locations and Impacts on IPE							
FA	FZONE	Impact	RACEWAY	CBL	System	Component	Affect
FA52	602XL	KAR	2TH888N	2NNSXNH302	KA	2NNS-SWG016	F
FA52	602XL	KAR	2TH888N	2NNSXNH303	KA	2NNS-SWG016	F
FA52	602XL	KAR	2TH889N	2NNSXNH301	KA	2NNS-SWG016	F
FA52	602XL	KAR	2TH889N	2NNSXNH302	KA	2NNS-SWG016	F
FA52	602XL	KAR	2TH889N	2NNSXNH303	KA	2NNS-SWG016	F
FA52	602XL	KAR	2TH890N	2NNSXNH301	KA	2NNS-SWG016	F
FA52	602XL	KAR	2TH890N	2NNSXNH302	KA	2NNS-SWG016	F
FA52	602XL	KAR	2TH890N	2NNSXNH303	KA	2NNS-SWG016	F
FA52	602XL	KAR	2TH891N	2NNSXNH301	KA	2NNS-SWG016	F
FA52	602XL	KAR	2TH891N	2NNSXNH302	KA	2NNS-SWG016	F
FA52	602XL	KAR	2TH891N	2NNSXNH303	KA	2NNS-SWG016	F
FA52	602XL	KBR	2TK852N	2NNSBNK604	KB	2NNS-SWG017	FAI
FA52	602XL	KBR	2TK854N	2NNSANK604	KB	2NNS-SWG017	FAI
FA52	602XL	KBR	2TK856N	2NNSANK604	KB	2NNS-SWG017	FAI
FA52	602XL	KA	2TK856N	2SPFXNK600	KA	2YUL-MDS1	FAI
FA52	602XL	KR	2TK856N	2SPFXNK601	KR	2YUC-MDS10	FAI
FA52	602XL	KBR	2TK857N	2NNSANK604	KB	2NNS-SWG017	FAI
FA52	602XL	KA	2TK857N	2SPFXNK600	KA	2YUL-MDS1	FAI
FA52	602XL	KR	2TK857N	2SPFXNK601	KR	2YUC-MDS10	FAI
FA52	602XL	KBR	2TK858N	2NNSANK604	KB	2NNS-SWG017	FAI
FA52	602XL	KA	2TK858N	2SPFXNK600	KA	2YUL-MDS1	FAI
FA52	602XL	KR	2TK858N	2SPFXNK601	KR	2YUC-MDS10	FAI
FA52	602XL	KB	2TK863N	2SPFYNK600	KB	2YUL-MDS2	FAI
FA52	602XL	KBR	2TK864N	2NNSBNK604	KB	2NNS-SWG017	FAI
FA52	602XL	KB	2TK864N	2SPFYNK600	KB	2YUL-MDS2	FAI
FA52	602XL	KBR	2TK865N	2NNSBNK604	KB	2NNS-SWG017	FAI
FA52	602XL	KB	2TK865N	2SPFYNK600	KB	2YUL-MDS2	FAI
FA52	602XL	KB	2TK866N	2SPFYNK600	KB	2YUL-MDS2	FAI
FA52	602XL	KR	2TK866N	2SPFYNK601	KR	2YUC-MDS20	FAI
FA52	602XL	KR	2TK867N	2SPFYNK601	KR	2YUC-MDS20	FAI
FA52	602XL	KA	2TK869N	2SPFXNK600	KA	2YUL-MDS1	FAI
FA52	602XL	KR	2TK869N	2SPFXNK601	KR	2YUC-MDS10	FAI
FA52	602XL	KA	2TK871N	2SPFXNK600	KA	2YUL-MDS1	FAI
FA52	602XL	KR	2TK871N	2SPFXNK601	KR	2YUC-MDS10	FAI
FA52	602XL	KR	2TK871N	2SPFYNK601	KR	2YUC-MDS20	FAI
FA52	602XL	KBR	2TK875N	2NNSBNK604	KB	2NNS-SWG017	FAI
FA52	602XL	KB	2TK875N	2SPFYNK600	KB	2YUL-MDS2	FAI
FA52	602XL	KB	2TK940N	2SPFYNK600	KB	2YUL-MDS2	FAI

Table 4.6-1 LOSP Cable Database With Locations and Impacts on IPE							
FA	FZONE	Impact	RACEWAY	CBL	System	Component	Affect
FA53	603NZ	KR	2CC860NH	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA53	603NZ	KA	2CC860NK	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA53	603NZ	KR	2CC860NK	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA53	603NZ	KA	2CC860NQ	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA53	603NZ	KA	2CC860NQ	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA53	603NZ	KAR	2CH886NA	2NNSXNH301	KA	2NNS-SWG016	F
FA53	603NZ	KAR	2CH886NB	2NNSXNH302	KA	2NNS-SWG016	F
FA53	603NZ	KAR	2CH886NC	2NNSXNH303	KA	2NNS-SWG016	F
FA53	603NZ	KA	2CK872NE	2SPFXNK600	KA	2YUL-MDS1	FAI
FA53	603NZ	KR	2CK872NE	2SPFXNK601	KR	2YUC-MDS10	FAI
FA53	603NZ	KA	2TC860N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA53	603NZ	KR	2TC860N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA53	603NZ	KA	2TC860N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA53	603NZ	KA	2TC860N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA53	603NZ	KR	2TC860N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA53	603NZ	KBR	2TH880N	2NNSYNH302	KB	2NNS-SWG017	F
FA53	603NZ	KBR	2TH880N	2NNSYNH303	KB	2NNS-SWG017	F
FA53	603NZ	KAR	2TH886N	2NNSXNH301	KA	2NNS-SWG016	F
FA53	603NZ	KAR	2TH886N	2NNSXNH302	KA	2NNS-SWG016	F
FA53	603NZ	KAR	2TH886N	2NNSXNH303	KA	2NNS-SWG016	F
FA53	603NZ	KA	2TK871N	2SPFXNK600	KA	2YUL-MDS1	FAI
FA53	603NZ	KR	2TK871N	2SPFXNK601	KR	2YUC-MDS10	FAI
FA53	603NZ	KR	2TK871N	2SPFYNK601	KR	2YUC-MDS20	FAI
FA53	603NZ	KA	2TK872N	2SPFXNK600	KA	2YUL-MDS1	FAI
FA53	603NZ	KR	2TK872N	2SPFXNK601	KR	2YUC-MDS10	FAI
FA53	603NZ	KR	2TK872N	2SPFYNK601	KR	2YUC-MDS20	FAI
FA55	604NZ	KB	2TC852N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA55	604NZ	KR	2TC852N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA55	604NZ	KB	2TC852N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA55	604NZ	KR	2TC852N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA55	604NZ	KBR	2TH881N	2NNSYNH302	KB	2NNS-SWG017	F
FA55	604NZ	KBR	2TH881N	2NNSYNH303	KB	2NNS-SWG017	F
FA55	604NZ	KBR	2TH882N	2NNSYNH302	KB	2NNS-SWG017	F
FA55	604NZ	KBR	2TH882N	2NNSYNH303	KB	2NNS-SWG017	F
FA55	604NZ	KR	2TK867N	2SPFYNK601	KR	2YUC-MDS20	FAI
FA78	612XL	KAR	2CC894NB	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA78	612XL	KAR	2TC894N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA78	612XL	KAR	2TC895N	2NNSXNC303	KA	2NNS-SWG016	T, FAI

Table 4.6-1 LOSP Cable Database With Locations and Impacts on IPE							
FA	FZONE	Impact	RACEWAY	CBL	System	Component	Affect
FA78	612XL	KBR	2TC896N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA78	612XL	KAR	2TC897N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA78	612XL	KBR	2TK888N	2NNSANK604	KB	2NNS-SWG017	FAI
FA78	612XL	KBR	2TK894N	2NNSANK604	KB	2NNS-SWG017	FAI
FA78	612XL	KBR	2TK895N	2NNSANK604	KB	2NNS-SWG017	FAI
FA78	612XL	KBR	2TK904N	2NNSANK604	KB	2NNS-SWG017	FAI
FA78	612XL	KBR	2TK904N	2NNSBNK604	KB	2NNS-SWG017	FAI
FA79	613XL	KBR	2CC896NA	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA79	613XL	KBR	2CK904NC	2NNSANK604	KB	2NNS-SWG017	FAI
FA79	613XL	KBR	2CK904NC	2NNSBNK604	KB	2NNS-SWG017	FAI
FA79	613XL	KA	2TC850N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA79	613XL	KR	2TC850N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA79	613XL	KB	2TC850N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA79	613XL	KR	2TC850N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA79	613XL	KA	2TC850N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA79	613XL	KA	2TC850N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA79	613XL	KB	2TC850N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA79	613XL	KR	2TC850N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA79	613XL	KA	2TC878N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA79	613XL	KR	2TC878N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA79	613XL	KB	2TC878N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA79	613XL	KR	2TC878N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA79	613XL	KA	2TC878N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA79	613XL	KA	2TC878N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA79	613XL	KB	2TC878N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA79	613XL	KR	2TC878N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA79	613XL	KBR	2TC896N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA79	613XL	KAR	2TC897N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA79	613XL	KAR	2TC898N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA79	613XL	KBR	2TC898N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA79	613XL	KAR	2TC900N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA79	613XL	KBR	2TC900N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA79	613XL	KA	2TC933N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA79	613XL	KR	2TC933N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA79	613XL	KB	2TC933N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA79	613XL	KR	2TC933N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA79	613XL	KA	2TC933N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA79	613XL	KA	2TC933N	2YUCXNC308	KA	2YUS-MDS3	T, FAI

Table 4.6-1 LOSP Cable Database With Locations and Impacts on IPE							
FA	FZONE	Impact	RACEWAY	CBL	System	Component	Affect
FA79	613XL	KB	2TC933N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA79	613XL	KR	2TC933N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA79	613XL	KBR	2TH857N	2NNSYNH302	KB	2NNS-SWG017	F
FA79	613XL	KBR	2TH857N	2NNSYNH303	KB	2NNS-SWG017	F
FA79	613XL	KAR	2TH860N	2NNSXNH301	KA	2NNS-SWG016	F
FA79	613XL	KAR	2TH860N	2NNSXNH302	KA	2NNS-SWG016	F
FA79	613XL	KAR	2TH860N	2NNSXNH303	KA	2NNS-SWG016	F
FA79	613XL	KBR	2TK852N	2NNSBNK604	KB	2NNS-SWG017	FAI
FA79	613XL	KBR	2TK854N	2NNSANK604	KB	2NNS-SWG017	FAI
FA79	613XL	KBR	2TK895N	2NNSANK604	KB	2NNS-SWG017	FAI
FA79	613XL	KBR	2TK896N	2NNSBNK604	KB	2NNS-SWG017	FAI
FA79	613XL	KBR	2TK897N	2NNSBNK604	KB	2NNS-SWG017	FAI
FA79	613XL	KBR	2TK898N	2NNSBNK604	KB	2NNS-SWG017	FAI
FA79	613XL	KBR	2TK902N	2NNSANK604	KB	2NNS-SWG017	FAI
FA79	613XL	KBR	2TK903N	2NNSBNK604	KB	2NNS-SWG017	FAI
FA79	613XL	KBR	2TK904N	2NNSANK604	KB	2NNS-SWG017	FAI
FA79	613XL	KBR	2TK904N	2NNSBNK604	KB	2NNS-SWG017	FAI
FA88	331NW	KA	2TC511N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA88	331NW	KR	2TC511N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA88	331NW	KB	2TC511N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA88	331NW	KR	2TC511N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA88	331NW	KA	2TC511N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA88	331NW	KA	2TC511N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA88	331NW	KB	2TC512N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA88	331NW	KR	2TC512N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA88	331NW	KAR	2TC513N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA88	331NW	KBR	2TC513N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA88	331NW	KA	2TC514N	2SPFXNC614	KA	2YUL-MDS1	T, FAI
FA88	331NW	KR	2TC514N	2SPFXNC615	KR	2YUC-MDS10	T, FAI
FA88	331NW	KB	2TC514N	2SPFYNC614	KB	2YUL-MDS2	T, FAI
FA88	331NW	KR	2TC514N	2SPFYNC615	KR	2YUC-MDS20	T, FAI
FA88	331NW	KA	2TC514N	2YUCXNC301	KA	2YUS-MDS3	T, FAI
FA88	331NW	KA	2TC514N	2YUCXNC308	KA	2YUS-MDS3	T, FAI
FA88	331NW	KAR	2TC516N	2NNSXNC303	KA	2NNS-SWG016	T, FAI
FA88	331NW	KBR	2TC516N	2NNSYNC301	KB	2NNS-SWG017	T, FAI
FA88	331NW	KB	2TC518N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA88	331NW	KR	2TC518N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA88	331NW	KB	2TC521N	2YUCYNC301	KB	2YUC-MDS4	T, FAI

Table 4.6-1 LOSP Cable Database With Locations and Impacts on IPE							
FA	FZONE	Impact	RACEWAY	CBL	System	Component	Affect
FA88	331NW	KR	2TC521N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA88	331NW	KB	2TC526N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA88	331NW	KR	2TC526N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA88	331NW	KB	2TC532N	2YUCYNC301	KB	2YUC-MDS4	T, FAI
FA88	331NW	KR	2TC532N	2YUCZNC300	KR	2YUC-MDS5	T, FAI
FA88	331NW	KAR	2TH500N	2NNSXNH301	KA	2NNS-SWG016	F
FA88	331NW	KAR	2TH500N	2NNSXNH302	KA	2NNS-SWG016	F
FA88	331NW	KAR	2TH500N	2NNSXNH303	KA	2NNS-SWG016	F
FA88	331NW	KBR	2TH501N	2NNSYNH302	KB	2NNS-SWG017	F
FA88	331NW	KBR	2TH501N	2NNSYNH303	KB	2NNS-SWG017	F
FA88	331NW	KBR	2TH508N	2NNSYNH302	KB	2NNS-SWG017	F
FA88	331NW	KBR	2TH508N	2NNSYNH303	KB	2NNS-SWG017	F
FA88	331NW	KBR	2TH513N	2NNSYNH302	KB	2NNS-SWG017	F
FA88	331NW	KBR	2TH513N	2NNSYNH303	KB	2NNS-SWG017	F

Table 4.6-2 Control Room Panels Evaluation			
Panel/Bay	Drawings	Description of Impacts on Systems	Impact on IPE (Initiator & Top Events)
601/A	4CEC13/113	Div I service water, Div I & II SWP MOVs to RBCLC	SA, RW
601/B	4CEC13/113	Div II service water, RBCLC, TBCLC, Div I & II SWP MOVs to TBCLC	SB, RW, TW
601/C	4CEC13/113	RCIC	IC
601/D	4CEC13/113	LPCS, RHR "A" including SWP & RBCLC AOVs for pump cooling	LS, LA, HA
601/E	4CEC13/113	ADS-SRVs, ADS inhibit & actuation	SV
601/F	4CEC13/113	RHR "C" & RHR "B" including SWP & RBCLC AOVs for pump cooling	LB, HB
601/G	4CEC13/113	Standby liquid control, HPCS	SL, HS
602/A	4CEC14/114	Recirc pump control & cooling	plant trip
602/B	4CEC14/114	Recirc pump control & cooling, MSIVs, Div I & II maual isol	IS, CV
602/C	4CEC14/114	RWCU	plant trip
603/A	4CEC15/115	FW level control & isol, Rx controls, Rx drain isol (DER*MOV128&129), APRM	FW, IS, SCRAM
603/B	4CEC15/115	Rod select insert, IRM/APRM, Sram & Reset	SCRAM & Reset
603/C	4CEC15/115	IRM, CRD auxiliaries, SDV, RRCS, Mode switch	Scram, Mode Switch (CN)
851/A	4CEC02/102	T/G auxiliaries, EHC	CN, turbine trip
851/B	4CEC02/102	Instrument air, gland steam, clean steam reboiler	AS
851/C	4CEC02/102	Circulating Water	CN
851/D	4CEC02/102	Condenser air removal, MSR, FW heater drains	CN, FW
851/E	4CEC02/102	Condensate & feedwater and condensate transfer	CN, FW
852/A	4CEC01/101	Div I AC power including SWP MOV to EDG	A1
852/B	4CEC01/101	Normal & Div II AC power including SWP MOV to EDG	OG, A2
852/C	4CEC01/101	Normal & Div III AC power including SWP MOVs to EDG	OG, HS

Table 4.6-2 Control Room Panels Evaluation			
Panel/Bay	Drawings	Description of Impacts on Systems	Impact on IPE (Initiator & Top Events)
852/D	4CEC01/101	Normal AC power & 115KV	OG, KA, KB, KR
852/E	4CEC01/101	Normal AC power & 115KV	OG, KA, KB, KR
852/F	4CEC01/101	Generator to switch yard (345KV)	Possible plant trip
824/A	4CEC16/116	RCIC stream drain MOV189, MSIV drains, other misc drains	IS
824/B	4CEC16/116	Main steam & turbine drains	IS
824/C	4CEC16/116	Main steam & turbine drains	IS
824/D	4CEC16/116	Main steam & turbine drains	IS
842/A	4CEC17/117	Turbine test control (TSV, TCV, CIV, Bypass valves)	CN, turbine trip
842/B	4CEC17/117	Turbine monitoring	-
842/C	4CEC17/117	Turbine monitoring	-
841		Turbine monitoring	-
623		Outboard containment isolation relays (MSIVs & MSIV drains)	CN
609/A	7.225-001-011	RPS trip system A - Recirc pump trip, TSVs, MSIVs, 1/2 SCRAM	CN
609/B	7.212-001-040	Isol logic, main steam drains, RHR logic, condenser low vacuum	CN, IA
609/C	7.212-001-040	Isol logic, main steam drains, RHR logic, condenser low vacuum	CN, IA
609/D	7.225-001-011	Recirc pump trip, TSVs, MSIVs, 1/2 SCRAM	CN
622		Inboard containment isolation relays (MSIVs & MSIV drains)	CN
611/A	7.225-001-011	RPS trip system B - Recirc pump trip, TSVs, MSIVs, 1/2 SCRAM	CN
611/B	7.212-001-041	Isol logic, main steam drains, RHR logic, condenser low vacuum	CN, IB, LC
611/C	7.212-001-041	Isol logic, main steam drains, RHR logic, condenser low vacuum	CN, IB, LC
611/D	7.225-001-011	Recirc pump trip, TSVs, MSIVs, 1/2 SCRAM	CN
606/A&C		SRM & IRM monitoring "A", MSIV closure	CN
659		Rod sequence control system	-
615		Control rod position information	-

Table 4.6-2 Control Room Panels Evaluation			
Panel/Bay	Drawings	Description of Impacts on Systems	Impact on IPE (Initiator & Top Events)
616		Control rod drive control	-
610		Control rod drive test	-
633/B&D		SRM & IRM monitoring "B", MSIV closure	CN
608/A-E		Power range monitoring	SCRAM
873/A	4CEC22/122	Div I & II containment equip & floor drain & RBCLC to drywell unit coolers isolation	IS
873/B	4CEC22/122	Div I & II RBCLC to drywell unit coolers, drywell temp recordes, CMS isolation valves	IS
873/C	4CEC22/122	Div I CMS H2/O2 analyzers, SFC, SWP to SFC	-
873/D	4CEC22/122	Div I spent fuel pool cooling, H2 recombiner 1A, containment purge	CV (AOV110 & 111)
870/A	4CEC19/119	Div I SGTS, Rx bldg HVAC unit coolers	-
870/B	4CEC19/119	Div I Rx bldg unit cooler 413A, control bldg HVAC	-
870/C	4CEC19/119	Div I control bldg HVAC, EDG HVAC, SWP bay HVAC	A1 (EDG)
871/A	4CEC20/120	Div II SGTS, Rx bldg HVAC & unit coolers	-
871/B	4CEC20/120	Div II Rx bldg unit cooler 413B, control bldg HVAC	-
871/C	4CEC20/120	Div II control bldg HVAC, EDG HVAC, SWP bay HVAC	A2 (EDG)
871/D	4CEC20/120	Div III HPCS HVAC, control & diesel bldg HVAC	HS
875/A	4CEC23/123	Div II CMS, H2/O2 analyzers	-
875/B	4CEC23/123	Div II SFC, H2 recombiner 1B, containment venting	CV (AOV108 & 109)
619		Jet pump instrument	-
629/A-B		Div I LPCS & RHR "A" process instumentation and relays, SLC	LA, LS, SL
628/A-B		Automatic depressurization system A relays, downcomer vac breakers	1/2SV actuation
621		RCIC Div I logic relays	IC (Div I actuation)
632/A-C		Div I leak detection (MSIV, RCIC & RHR temp trip isolation)	CN, IC

Table 4.6-2 Control Room Panels Evaluation			
Panel/Bay	Drawings	Description of Impacts on Systems	Impact on IPE (Initiator & Top Events)
618/A		Div II RHR "B" and "C" process intrumentation and relays	LB, LC
618/B		Div II RCIC logic	IC(Div II actuation)
618/C		EOP designated panel, RCIC, SLC, RHR	IC, SL, LB, LC
631		Automatic depressurization system B relays	1/2SV actuation
613		Leak detection instruments (steam tunnel delta T, 1/2 MSIV isol)	-
642		Div II leak detection (MSIV, RCIC & RHR temp trip isolation)	CN, IC
607/A-B		Tip control and monitoring	-
614/A-B		NSSS temperature recorders (recirc pump motors, SRVs, RPV)	-
612/A-C		Feedwater and recirculation instrument	FW
634/A-C		Reactor recirc flow control	-
625		HPCS process instrumentation and relays	HS
880/A-B	4CEC48/148	Div I digital radiation monitoring (Rx bldg HVAC, SWP)	-
880/C-D	4CEC48/148	Div II digital radiation monitoring (Rx bldg HVAC, SWP)	-
882		Met towers data	-
898		Post accident monitoring	-
849/A-C		Fire protection	-

Table 4.6-3 Relay Room Panels Evaluation			
Panel/Bay	Drawing	Description of Impacts on Systems	Impact on IPE (Initiator & Top Events)
828	EE-3D-5	Div I BOP instrument - Spent Fuel Pool Cooling, Service Water & CR HVAC instrument loops	SA
829	EE-3E-5	Div I BOP instrument - SW intake, DGB temp loops & Stby Gas Treatment Differnetial press controller	NONE - Loss of some circuits but with minimal impact.
890	EE-3P-5	Div I BOP instrument - CB HVAC & Containment Monitoring temperature loops	NONE - Loss of some circuits but with minimal impact.
896	EE-3V-5	Div I BOP instrument - Hydrogen Recombiner temperature loops	NONE - Loss of some circuits but with minimal impact.
888	EE-3N-7	BOP instrument _ Basin temperature loops & Circ Water tempering controls	NONE - Loss of some circuits but with minimal impact.
825	EE-3A-6	BOP instrument - Feedwater level controllers 10A, 10B & 10C	FW
826	EE-3B-4	BOP instrument - RBCLC temperature controller	RW
827	EE-3C-4	BOP instrument - TRBCLC temperature controller	TW
831	EE-3G-5	Div II BOP instrument, Service Water, CB HVAC, Spent Fuel Pool cooling	SB
830	EE-3F-5	Div II BOP instrument Service Water, DG Bldg HVAC & Standby Gas treatment	SB
891	EE-3R-4	Div II BOP instrument- CB HVAC, Cont Monitoring System	NONE - Loss of some circuits but with minimal impact.
897	EE-3W-5	Div II BOP instrument- Hydrogen Recombiner	NONE - Loss of some circuits but with minimal impact.
883	EE-3H-4	Div III BOP instrument- DG Bldg Temp Xmtrs	NONE - Loss of some circuits but with minimal impact.
887	EE-3M-5	BOP instrument- Turbine & generator temperature Xmtrs and controllers	NONE - Loss of some circuits but with minimal impact.
886	EE-3L-5	BOP instrument- Turning Gear, Cond Air Removal & Cont Purge	NONE - Loss of some circuits but with minimal impact.
885	EE-3K-6	BOP instrument- Moisture Separator & Reheater control Div B	NONE - Loss of some circuits but with minimal impact.

Table 4.6-3 Relay Room Panels Evaluation			
Panel/Bay	Drawing	Description of Impacts on Systems	Impact on IPE (Initiator & Top Events)
884	EE-3J-6	BOP instrument- Moisture Separator & Reheater control Div A	NONE - Loss of some circuits but with minimal impact.
806		Reserve trans 2RTX-XSR1A backup protection	KA
807		Auxiliary trans 2ATX-XS1 protection	NA
816		RTU interface	-
817		RTU interface	-
809		Reserve trans 2RTX-XSR1B backup protection	KB
810		Auxiliary trans 2ATX-XS3 protection	NB
815		2NPS-SWG002 protection & 2NNS-SWG012 backup protection	NA
802		Aux boiler service trans 2ABS-X1 backup protection	KR
805		Reserve trans 2RTX-XSR1A & 2NSS-SWG016 protection	KA
812		2NPS-SWG001 & 2NNS-SWG011 protection	NA
803		2NNS-SWG014 protection	NA
814		2NNS-SWG012 protection	NA
808		Reserve trans 2RTX-XSR1B & 2NSS-SWG017 protection	KB
813		2NPS-SWG003 protection & 2NNS-SWG013 protection	NB
804		2NNS-SWG015 protection	NB
811		Aux boiler service trans 2ABS-X1 & 2NSS-SWG018 protection	KR
001/A-C		RRCS	RRCS actuation
876	0007.520_001_114	345KV switch yard transfer trip relays ALT 1	Turbine Trip
899/A-H	EE-3ES	ERF isolators	-
002/A-C		RRCS	RRCS actuation
877	0007.520_001_115	345KV switch yard transfer trip relays ALT 2	Turbine Trip
894	EE-3S	Div I suppression pool temperature monitoring	-

Table 4.6-3 Relay Room Panels Evaluation			
Panel/Bay	Drawing	Description of Impacts on Systems	Impact on IPE (Initiator & Top Events)
140	EE-3TD	2SVV*IPNL140 SRV indication monitoring	-
856/A	0007.520_001 _199	Auxiliary relays Aux steam Div N, condensate Div N, DG ventilation Div N, condensate make up Div N	NONE
856/B	0007.520_001 _199	Misc Turbine drains Div N	NONE - Loss of some circuits but with minimal impact.
856/C	0007.520_001 _199	Turbine drains Div N, Gen stator cooling	NONE - Loss of some circuits but with minimal impact.
856/D	0007.520_001 _200	Turbine drains Div N, Circ water Div N, TBCLCWs Div N	NONE - Loss of some circuits but with minimal impact.
856/E	0007.520_001 _200	Emerg Gen fuel alarm relays, lube oil lift pumps, CR HVAC Div N	NONE - Loss of some circuits but with minimal impact.
856/F	0007.520_001 _200	Inst Air Div I, Drywell Cooling Div N, RB HVAC Div N	1/2 AS
874/A	0007.520_001 _194	Div III isolators & auxiliary relays Bypass and Inoperable status system for Div III D/G	HS
874/B	0007.520_001 _194	Div III isolators & auxiliary relays - Bypass and Inoperable status system	HS
874/C	0007.520_001 _194	Div III isolators & auxiliary relays - Bypass and Inoperable status system	HS
874/D	0007.520_001 _194	none	NONE - Loss of some circuits but with minimal impact.
895	EE-11HB	Div II suppression pool temperature monitoring	-
893	EE-11HH	Vibration monitoring	-
892	EE-3GB	Loose parts monitoring	-
889	EE-3KH	Seismic instrumentation	-
857/A	0007.520_001 _204	Auxiliary relays : Turbine plant relays, condenser air removal, lube oil, drains and gland & exhaust steam	NONE - Loss of some circuits but with minimal impact.
857/B	0007.520_001 _204	Heater drains drywell cooling Div B, CR HVAC Div B, low press drains	NONE - Loss of some circuits but with minimal impact.

Table 4.6-3 Relay Room Panels Evaluation			
Panel/Bay	Drawing	Description of Impacts on Systems	Impact on IPE (Initiator & Top Events)
859/A	0007.520_001 _205	Div I auxiliary relays -Cont Monitoring, Cont Purge	NONE - Loss of some circuits but with minimal impact.
859/B	0007.520_001 _205	Div I auxiliary relays -Hydrogen Recombiner, CB HVAC, Main Steam, CB Chilled Water	NONE - Loss of some circuits but with minimal impact.
859/C	0007.520_001 _205	Div I auxiliary relays - Service Water & RBCLC	NONE - Loss of some circuits but with minimal impact.
859/D	0007.520	Non Vital Indication aux relays Div I, Reactor Recirculation Div I, EG air & fuel Div I	NONE - Loss of some circuits but with minimal impact.
859/E	0007.520_001 _206	Service Water Div I	NONE - Loss of some circuits but with minimal impact.
859/F	0007.520_001 _206	Misc Div I relays - Inst Air, Div I 4KV power & misc HVAC relays	NONE - Loss of some circuits but with minimal impact.
37/A-H	0007.520_001 _255 ,256	Div I isolators - Fire induced open circuits on the input wires have no adverse impact of Div I. Short circuits in the Div I input wires can have an impact ranging from no failures to a significant number of failures, the exact failure impact was not determined. However there are certain circuits where a short circuit has no impact. The expected level of damage is some small fraction of the Div I circuits feeding this isolation panel bay.	NOT DETERMINED
861/A	0007.520_001 _195	Div II auxiliary relays- Cont Monitoring System, Cont Purge, Drains	NONE - Loss of some circuits but with minimal impact.
861/B	0007.520_001 _195	Div II aux relays- Standby Gas Treatment, Hydrogen Recombiner, CR HVAC chilled water	NONE - Loss of some circuits but with minimal impact.
861/C	0007.520_001 _195	Div II aux relays- CR HVAC, RBCLC	NONE - Loss of some circuits but with minimal impact.
861/D	0007.520_001 _196	Div II aux relays- Non Vital control power, Service Water, EDG starting air & fuel, Reactor Recirc	NONE - Loss of some circuits but with minimal impact.
861/E	0007.520_001 _196	Div II aux relays- Non Vital control power, Service Water, EDG starting air & fuel	NONE - Loss of some circuits but with minimal impact.

Table 4.6-3 Relay Room Panels Evaluation			
Panel/Bay	Drawing	Description of Impacts on Systems	Impact on IPE (Initiator & Top Events)
861/F	0007.520_001 _196	Div II aux relays- Inst Air, Reactor and DG HVAC	NONE - Loss of some circuits but with minimal impact.
838/A-H	0007.520_001 _259 , 260	Div II isolators - Fire induced open circuits on the input wires have no adverse impact of Div I. Short circuits in the Div II input wires can have an impact ranging from no failures to a significant number of failures, the exact failure impact was not determined. However there are certain circuits where a short circuit has no impact. The expected level of damage is some small fraction of the Div I circuits feeding this isolation panel bay.	NOT DETERMINED
858/A-S		BOP annunciator logic & retransmitting relays	-
833/A-M		BOP annunciator logic	-
881		GETARS	-
630/A-H	0007.520_001 _904 , ... 266	Remote annunciator electronics	NONE - Loss of some circuits but with minimal impact.
848		Turbine EHC	turbine trip
847		Turbine EHC	turbine triip
846		Turbine EHC	turbine trip
845		Turbine EHC	turbine trip
844		Turbine EHC	turbine trip
843		Turbine EHC	turbine trip
869		Generator main transformer & NSS transformer relays	turbine trip
868		Generator main transformer & NSS transformer relays	turbine triip
867		Generator main transformer & NSS transformer relays	turbine trip
866		Generator main transformer & NSS transformer relays	turbine trip
865		Generator main transformer & NSS transformer relays	turbine trip
864		Generator main transformer & NSS transformer relays	turbine trip

Table 4.6-4 Division II Standby Switchgear Room (FA19 336XL) Cabinets Evaluation			
Cabinet/Bay	Drawing	Description of Impacts on Systems	Impact on IPE (Initiator & Top Events)
2LAC*XLE02	EE-11Z	Room lighting transformer	-
2LAC*PNLE02	EE-11Z	Room lighting panels	-
2HVC*PNL302	EE-9NE	2HVC*FN2B	-
2VBA*UPS2B	EE-11DC	Vital UPS 2B	UB
2EHS*MCC303		EDG auxiliaries, HVAC, MOVs (subset of US3 impact below)	Subset of US3 impact below
2ENS-BTC3	EE-8DL	Breaker test station	-
2BYS*CHGR2B2	EE-10AX	1 of 2 AC supplies to 2BYS*SWG002B	Backup AC supply in D2
2LAC*PNL300B	EE-11CA	1 of 2 AC supplies to UPS 2B and AC supply to CHG2B1. Also supplies 2SCM*PNL301B, 302B, 303B, 304B, 305B	1/2 AC supply to UB and D2
2EJS*PNL300B	EE-11CA	1 of 2 AC supplies to UPS 2B and AC supply to CHG2B2. Also feeds 2EJA*PNL300B & 301B. 300B supplies RHR motor heaters and HVAC room heaters	1/2 AC supply to UB and D2
2EJA*XD301B	EE-11E	feeds 2EJA*PNL301B below	-
2EJA*PNL301B	EE-11E	Unit coolers and process radiation monitoring	-
2BYS*CHGR2B1	EE-10AK	1 of 2 AC supplies to 2BYS*SWG002B	AC supply in D2 (assumed operating)
2LAC*XLE05	EE-11Z	Room lighting transformer	-
2LAC*XLE07	EE-11Z	Room lighting transformer	-
2EJS-BTC3	EE-9PC	Breaker test station	-
2BYS*SWG002B		Div II DC power	D2
2EJS*X3A		Normal feed to US3 below, 2EJS*X3B provides backup.	Same as US3 except there is a backup transformer to supply US3
2EJS*US3	EE-9QG	600V AC and lower Div II AC supplies. Systems normally operating systems such as service water are not affected. Standby pumps can be started.	A2 except pumps continue to operate and pumps can be started. MOVs must be locally operated.
2EJS*X3B		Backup feed to US3 above, 2EJS*X3A is normally aligned.	-
2ENS*SWG103		Div II AC power	A2

Table 4.6-5 Division I Cable Chase West Evaluation			
Fire Zone	Source	Impact From Source	Targets (impacts)
332NW	2HVC*AOD169	partial loss of ventilation (only smoke removal)	Up high at ceiling, suppression should mitigate
	2LAC PNL N04	emergency lighting battery	2CC987GS (2CES*PNL405), CR108 & 126 (security)
	Security Conc #2	security (low voltage)	2TX542N (loss of feedwater) and 543N (no impact)
352NW	2BYS*PNL201A	RCIC, LPCS, RHR "A", HPCS diesel, 1/2ADS, SWP ISOL if hot shorts, 1/2 Cont ISOL	
	2BYS*PNL202A	1/2RRCS	
	2SCM*PNL101A	Div I EDG, 1/2 manual cont ISOL, outboard CV valves	
	2SCM*PNL102A	Normal N2 to SRVs, N2 to Div I ADS SRVs	
	2SCM*PNL103A	1/2 manual cont ISOL	
	2SCM*PNL104A	alarms & indications	
	2SCM*PNL105A	Div I EDG, SLS pump 1A	
	2SCM*XD101A	see PNL101A above	2CL998GL (2SCM*PNL103A), 2CL998GK (2SCM*PNL102A) 2CK503GJ1 (2CSM*PNL104A), 2CK503GJ
	2SCM*XD102A	see PNL102A above	same as 2SCM*XD101A above
	2SCM*XD103A	see PNL103A above	2CC549GG (control bldg chilled water)
	2SCM*XD104A	see PNL104A above	2CK503GG1 (2SCM*PNL105A), 2TX536G (LPCS, RCIC, MSIVs, RHR "A", SLS "A", RBCLC to 2RCS-P1A)
	2SCM*XD105A	see PNL105A above	CR102 (security)
	2VBS*PNL101A	SLS pump 1A, N2 to Div I ADS from RSS, RRCS I, LPCS, RCIC, BOP (not normal AC power)	
	2VBS*PNL102A	radiation monitoring, post accident sampling	
371NW	2BYS-PNLA101	Recirc pump A, indications, CO2, RWCU demin panel	
	2BYS-PNLB101	Loss of Cond & FW Pumps, CO2, indications	
	2CES*PNL415	Div I disconnect	

Table 4.6-5 Division I Cable Chase West Evaluation			
Fire Zone	Source	Impact From Source	Targets (impacts)
	2CES-PNL417	FW disconnect	
	2SCA-PNL403	Main condenser, TBCLC	
	2SCA-XD403	see PNL403 above	
	2SCI-PNLA101	Cond & FW recirc, FW heaters, main condenser	
	2SCI-PNLB101	Cond & FW recirc, main steam reheaters, main condenser	
	2SCI-PNLB102	power to 2CES*PNL405 (RSS)	
	2VBS*PNLA103	1/2RPS, 1/2Cont ISOL, 1/2NSSSS, NMS (green)	
	2VBS*PNLB104	1/2RPS, 1/2NSSSS, NMS (orange)	
	2VBS-PNLA101	1/2ADS, power to BOP panels (feedwater, condenser, TBCLC, RBCLC), reactor recirc hyd, EHC, CRD	
	2VBS-PNLB101	Reactor recirc flow control, recirc pump 1A, CRD display, feedwater control	
	2LAC PNL N07	emergency lighting battery	2CC988GV (power to 2CES*PNL405 and RWCU isolation), CR105 (security)
	2LAC PNL N07	emergency lighting battery	2CX530GB (control bldg HVAC), 2CK541GA (empty)

4.7 Analysis of Containment Performance

Fires are very unlikely to have impact on passive structural components of the primary containment. The most likely ways identified for fires to impact containment performance are as follows:

- Core damage with containment isolation failure or bypass
- Core damage event causes containment failure (containment response)

<u>Containment Isolation</u>
The containment penetration screening analysis in the IPE[1] was reviewed. The containment isolation system is normally energized and the loss of electrical support results in a containment isolation. In addition, many normally open isolation valves fail closed on loss of their actuator support (i.e., instrument air, 120V AC power, and nitrogen). Other normally open paths are associated with closed systems or emergency core cooling and containment systems. In the IPE[1], normally open MOVs dominated containment isolation failure with station blackout scenarios important. Similarly, for fires, containment isolation failure and core damage due to station blackout is judged to dominate at a frequency less than 1E-6/yr based on the control room fire analysis in Section 4.6.2. The conditional probability that the operators fail to isolate MOVs outside containment given AC power failure is not included in the analysis. However, human reliability dominates the results which means that this is not a significant conservatism. The contribution of containment isolation failure to early large release in the IPE[1] is about 3.6E-7/yr. Based on the control room analysis in Section 4.6.2, the contribution is about 2E-7/yr from station blackout scenarios which take no credit for operator actions.

<u>Containment Bypass</u>
Containment bypass due to a fire induced LOCA outside containment is considered to be an insignificant contributor to risk for the following reasons:

- Shutdown cooling suction & discharge and steam condensing suction paths to RHR "A" and "B" have at least two normally closed MOVs and one of the MOVs is de-energized. The likelihood of a closed de-energized valve opening during a fire event is negligible.

- RHR "B" head spray (through RCIC head spray) has several check valves and a normally closed MOV. A fire caused interfacing LOCA through this path is negligible.

- The LPCS and LPCI "A", "B" and "C" injection paths have a normally closed MOV and a check valve. The MOV in each path receives a permissive to open on low differential pressure <u>and</u> pump start signal or manual system initiation signal.

Panel P618 in the control room contains circuits for both isolation valves in the LPCI/LPCS injection lines. There is a testable check valve inside the drywell and a closed MOV outside of the drywell. Both valves must open for an ISLOCA to occur. Two fire induced short circuits can develop an open demand for each valve. However, the LPCI/LPCS motor operated injection valves cannot open if the delta P across the valve is greater than 675 psi. This is because the valve motor cannot generate sufficient thrust to overcome the friction developed at this loading. Also, the downstream check valve has an air operator to facilitate testing. It is only tested at refueling or when the unit is in a cold shutdown condition. During plant operation, the air to this operator is shut off. This will prevent the testable check valve from opening even if it's solenoid is opened by a fire. Thus, the likelihood that a fire will contribute to the probability of both valves being open (an MOV and a check valve) is negligible.

An interfacing LOCA is unlikely based on the above. Even the possibility of a fire induced hot short spuriously causing the permissive required for LPCS and LPCI is an unlikely scenario since a check valve disc would also have to fail. In addition, the LPCS and RHR piping systems were assessed to have high pressure capacities in the IPE. Thus, the frequency of a fire caused hot short (<1E-3/yr) and check valve failure (<1E-3/demand) and pipe failure outside containment that leads to core damage (<1E-3/demand) is very unlikely (<1E-9/yr).

<u>Containment Response</u>

Containment response to core damage events with the containment isolated could be obtained by quantifying the dominant fire initiators with the IPE Level 2 model. The following summarizes the contributions of accident sequence types to early containment failure in the IPE:

Sequence Type	Annual Frequency	Conditional Frequency
Loss of Inj - RPV Press High	4.10E-07	0.013
Loss of Inj - RPV Press Low	1.70E-07	0.005
Loss of Inj - Blackout	4.60E-08	0.001
Other (ATWS, Vapor Suppression)	1.74E-07	0.006
Total	8.00E-07	0.026

The vapor suppression and ATWS contributions to early containment failure are judged to be even less likely than in the IPE because the frequency of a fire induced LOCA or scram failure is much less. The dominant scenarios from the fire analysis are control room fires with loss of injection which could include any of the other three cases shown in the above table. Taking the total core damage frequency for control room fires (on the order of 1E-6/yr) and multiplying this by the above conditional frequencies (0.02) given core damage, would indicate an early release frequency of about 2E-8/yr.

4.8.5 Control Systems Interactions

The safe shutdown scenario for a fire in the Control Room or Relay Room is discussed in USAR Section 9B.8.2 and concludes that the concern presented by the Sandia Fire Risk Scoping Study pertaining to control systems interaction has been addressed.

All controls for systems required to achieve and maintain safe shutdown in the event of a fire within the Control Room have transfer or isolation switches located outside the Control Room. Procedures are in place which outline the shutdown procedure utilizing the remote shutdown system and actions to be taken prior to evacuating the Control Room in the event of a fire. These procedures and the Control Room evacuation scenario are discussed in Section 4.6.

Based on this circuitry and procedures, the issue of control system interactions has been addressed to satisfy the Sandia concern.

4.8 Treatment of Fire Risk Scoping Issues

4.8.1 Seismic/Fire Interaction

4.8.1.1 Seismically Induced Fires

Based on the results of the seismic margins assessment (SMA), seismic walkdowns, and fire protection walkdowns, and the design review activities described below, it is concluded that the fire protection program adequately minimizes risk.

The concern of seismically induced fires focuses on the potential for seismic events to cause a release of flammable or combustible liquids or gases. Hydrogen piping within the plant was not a relevant hazard since this piping is not normally pressurized. Hydrogen is dispensed from outside storage tanks on an as-needed batch basis and the supply valves are closed unless dispensing is being performed. This operation is performed on a bi-daily basis for approximately 2 hours. In addition, an excess flow valve is installed to limit hydrogen flow in the event of piping rupture and the generator is equipped with emergency hydrogen dump capability. The hydrogen piping system is confined to the west end of the turbine building where no safety related equipment is located. Hydrogen detectors are installed in areas of likely leaks. This hydrogen arrangement is an acceptable alternative to resolve Generic Safety Issue 106, "Piping and the Use of Highly Combustible Gases in Vital Areas" as discussed in NRC Generic Letter 93-06. The probability of seismically induced fires from this source causing core damage is very small.

During the plant walkdowns for the fire protection portion of IPEEE, combustible liquid tanks and/or piping were observed in the areas listed below:

Fire Area	Fire Zone	Description
66	402SW	Div. I EDG Day Tank Room
67	403SW	Div. II EDG Day Tank Room
68	404SW	Div. III (HPCS) EDG Day Tank Room
28	402SW	Div. I EDG Room
29	403SW	Div. II EDG Room
30	404SW	Div. III (HPCS) EDG Room
82	732NW	Turbine Lube Oil Storeroom
42	708NW	Turbine Lube Oil Storage Room
50	Various	General Areas of the Turbine Building
60	808NZ	Auxiliary Boiler Building
62	804NW	Diesel Fire Pump Room

While a seismic event could cause a release of flammable or combustible liquid from the tanks or piping within the areas listed, the impact would be minimized by several design features, including the following:

- All of the tank storage areas are diked to contain any spill within the area of origin.
- Areas with flammable/combustible liquid piping have floor drains to prevent spills from migrating into other fire areas.
- Fire detection is provided in all areas with flammable or combustible liquid tanks or piping so that a fire would be promptly detected.
- Automatic fire suppression systems are installed in all areas containing flammable or combustible liquid tanks or piping, except for zone 808NZ.

In addition to the design considerations, fire brigade training includes strategy and tactics exercises for fighting flammable and combustible liquid fires.

Fire areas 66, 67, 68, 28, 29 and 30 contain safety related equipment required to function in response to design basis accidents. Diesel fuel oil supplies and related equipment are seismically designed to preclude failure and were evaluated as part of the SMA scope. If an event beyond the design causes a fuel oil leak, the applicable EDG is rendered inoperable, regardless of any ensuing fire. As described above, propagation between fire areas is difficult. Also, the seismic margins assessment indicates that the capacity of this equipment is well above the design basis earthquake.

The risk of seismic fires in these areas is enveloped by the seismic PRA risk described in Section 3.2. The reason for this is two-fold:

1. Station blackout risk is dominated by seismic loss of offsite power and nonseismic failure of both Div I and II diesels.
2. Station blackout risk from seismic loss of offsite power and seismic common cause failure of all diesels is modelled with a HCLPF of 0.5g (used as screening value - all safety related equipment met this criteria).

The risk from the two scenarios above is low. Thus, seismic fire risk in these areas is low.

Fire areas 82, 42, 50, 60 and 62 are non-safety related areas and no equipment in these areas is included in the seismic margin success path. Thus, these fire sources were not evaluated in the SMA. From a fire PRA perspective, the seismic capacity of offsite power is low and can be assumed to envelope the failure probability of nonsafety equipment due to the earthquake. Also, propagation from these areas to other important areas is judged unlikely. Thus, the risk significance of fires in these areas is low and enveloped by the loss of offsite power fragility.

Since the major fire sources were either in the SMA scope or sufficiently removed, spatially, from components in the SMA scope, no special seismic/fire walkdown was needed. However, there was coordination of seismic and fire walkdowns as described in Section 3.1.1.

4.8.1.2 Seismic Actuation of Fire Suppression Systems

The fire detection panels at NMP2 use circuit boards for the logic functions rather than switches and relays used in older style panels which were susceptible to inadvertent activation during a seismic event. Inadvertent actuation of Halon and carbon dioxide due to detection system actuation would result in the release of extinguishing agent. Inadvertent operation of a Halon or carbon dioxide system would not result in any equipment operability concern, although in the case of a carbon dioxide actuation, persons entering the area of the discharge would require the use of self contained breathing apparatus until the area was purged and sufficient oxygen was present.

Four types of water-based fire suppression systems are installed at NMP2, as follows:

1. Wet Pipe Sprinkler Systems - These systems employ automatic sprinklers attached to a piping system that contains water under pressure at all times. When a fire occurs, individual sprinklers are actuated by the heat generated by the fire, and water flows through the sprinklers immediately.

2. Dry Pipe Sprinkler Systems - These systems have automatic sprinklers attached to piping that contains air under pressure. When a sprinkler is opened by heat from a fire, the pressure is reduced to the point where water pressure on the supply side of the dry pipe valve can force open the valve. Water then flows into the system and out any opened sprinklers.

3. Preaction Sprinkler Systems - These are systems in which there is air in the piping that may or may not be under pressure. When a fire occurs, a supplementary fire detecting device in the protected area is actuated. This opens a water control valve, which permits water to flow into the piping system before a sprinkler is activated. When sprinklers are subsequently opened by the heat of the fire, water flows through the sprinklers.

4. Water Spray Systems - These systems are equipped with open sprinklers connected to a piping system which is normally dry. A fire detection system actuates in the event of a fire, which opens a water control valve and permits water to flow into the piping system and immediately out of all the sprinkler nozzles simultaneously.

The systems installed at NMP2 are found in the following locations, by system type:

Wet Pipe Systems - Radwaste Building
Reactor Building Cable Tunnels
Control Building
Diesel Fire Pump Room
Turbine Building

Dry Pipe Systems - Turbine Building
Standby Gas Treatment Building

Preaction Systems - Reactor Building
Emergency Diesel Generator Rooms
Turbine Building

Water Spray Systems - Turbine Building
RCIC Pump Room
Radwaste Building

Since wet pipe systems, dry pipe systems and preaction systems each require the operation of individual sprinklers to cause system water flow, these systems are not susceptible to water discharge due to seismic-induced actuation during a seismic event. However, water spray systems, equipped with open sprinklers, would discharge water in the event of actuation of the water control valve during a seismic event. Therefore, the effects of such actuation are evaluated for the three areas in which these systems are installed, the Turbine Building, Radwaste Building and the RCIC Pump Room. For the Turbine Building and Radwaste Building, these areas are non-safety related and no equipment in the Turbine Building or Radwaste Building is included in the seismic margin success path. From a PRA perspective, the seismic capacity of offsite power is low and can be assumed to envelope the failure probability of nonsafety equipment due to the earthquake.

The RCIC room is protected from the effects of fire by an open pipe spray system actuated on high temperature. The detectors are Fenwal ceiling units that are actuated via thermal expansion. The thermal detectors actuate a fire relay that in turn actuates a solenoid that dumps the water holding the deluge valve closed thus allowing the valve to open to pass water.

Seismically induced spurious operation of this system can occur if the trim piping is breached or if the fire relay is sealed-in because of the vibratory motion. Actuation of the fire relay will exist only for the brief period of strong motion, i.e., for several seconds because the relay is not sealed in. The fire water will be sprayed into the RCIC room and possibly on RCIC components but not enough water will be sprayed to cause any damage.

The deluge valve can be opened if there is physical damage to the trim piping for the deluge valve. In this case, water would flow and flood the RCIC room rendering it inoperable. Physical damage can be caused directly by the event or from Seismic II/I considerations. However, investigation of the seismic supports for the fire manifold revealed that it's seismic capability is in excess of 0.5g and there are no Seismic II/I concerns in the vicinity of the deluge valve.

In addition to the above, the IPE considered internal flooding which included the potential actuation of fire suppression systems. Inadvertent actuation of fire protection systems as discussed in NRC Information Notice 83-41 is evaluated in Section 4.8.4.

Based on this analysis and Section 3.1.2.1.5, fire water and specific deluge valves associated with the control building emergency switchgear areas and RCIC were considered in the SMA.

4.8.1.3 Seismic Degradation of Fire Suppression Systems

NMP2 was designed and is maintained with Seismic II over I (II/I) requirements. This requires that non-seismic equipment, such as fire protection piping, be installed in such a way that it can not fall onto, or otherwise cause failure, of equipment which is required to mitigate a seismic event. The industry criteria for assuring that fire suppression systems meet this requirement is to assure that the fire suppression system has been installed in accordance with National Fire Protection Association (NFPA) codes and standards. NMP2 fire suppression systems have all been installed in accordance with the appropriate standard for the system type, including the requirements for supports and hangers. This conformance gives adequate assurance that the fire suppression systems will not fall on required safe shutdown components during a seismic event.

Further, the fire suppression systems are installed to minimize the affect of a seismic event through the use of cross zone actuation and/or use of preaction sprinklers. The installation of the fire suppression systems was reviewed during fire protection walkdowns to assure installation in accordance with NFPA codes and standards. No deviations from the installation standards which might adversely impact safe shutdown were noted during either walkdown. Also, the seismic analysis considered these type of interactions.

4.8.2 Fire Barrier Qualification/Effectiveness

Based on this review of fire barrier design, installation and surveillance requirements, the fire barriers credited within the analysis are considered to be adequate and effective at minimizing plant risk.

<u>Fire Barrier Materials</u>
The fire barrier program at NMP2 consists of design, installation, surveillance and maintenance criteria which assure effective fire barrier performance in the event of fire. Specifically, all four primary fire barrier components are included in the program: the barrier itself (wall or floor), fire doors, penetration seal assemblies, and fire dampers.

The fire barriers are derived from National Fire Protection Association (NFPA) material and thickness requirements and/or specific tested configurations such as those listed by Underwriters' Laboratories, Inc. An ongoing program of periodic inspection is in place to assure that fire barriers are maintained in accordance with original design. Identified deficiencies are promptly corrected in accordance with plant procedures.

Fire Doors
All fire doors in rated fire barriers are included in a comprehensive inspection and maintenance program. All fire doors are inspected on a daily basis to assure that they are maintained in their correct position. Deviations from the normal position are allowed in accordance with plant procedures, with appropriate compensatory measures in place to mitigate the deviation. Required maintenance for fire doors is identified through the periodic operation of each fire door or identification of necessary maintenance through the deviation reporting procedure utilized by all personnel on site.

Penetration Seal Assemblies
NMP2 examined the penetration seal assembly program extensively with the issue of NRC Information Notice (IN) 88-04, IN 88-04 Supplement 1, and IN 88-56. The overall conclusion of the NMP2 self-assessment of the impact of these Information Notices was documented in a 10/16/89 summary memo (file code NMP56322) which concluded that the NMP2 penetration seal assembly program considered the content of the Information Notices and all concerns were adequately addressed to preclude similar events.

Penetration seal assemblies are inspected on a periodic basis in accordance with plant procedures. These inspections are tailored to assure continued functionality of the penetration seal as originally designed. The program is based on a sampling technique which is an industry standard (10% of each design type with additional samples inspected if inoperable seals are identified). Deficiencies discovered by site personnel outside the scope of the surveillance procedure are identified via plant procedures for identification of plant deficiencies.

Fire Dampers
The concerns addressed in NRC IN 83-69 were considered in the original design of NMP2 and documentation is on file to document the corrective actions taken during construction to address each of the concerns.

Fire dampers are inspected on a periodic basis to assure operability in the event of a fire. Information Notice 89-52 addressed concerns of potential operational problems. All fire dampers have been tested to assure closure in their as-installed position under airflow conditions. In addition, plant procedures currently test the operation of the fire dampers with the ventilation system in the normal airflow condition. This approach satisfies the concern of operability of installed fire dampers at NMP2.

4.8.3 Manual Firefighting Effectiveness

Based on the evaluation of the established program for reporting fires, staffing and training of the fire brigade, periodic conduct of drills with critiques, and the maintenance of adequate training records, the NMP2 program for manual fire fighting adequately minimizes plant risk. The basis for this conclusion is described below.

Reporting Fires

General Employee Training (GET) provides the initial and retraining efforts for all employees within the Protected Area to receive instruction on the procedure to report plant fires. This includes instructions to notify the Control Room via the telephone or the Gai-Tronics system in the event of a fire discovered at the site.

Portable fire extinguishers are located throughout the plant in accordance with National Fire Protection Association (NFPA) Standard 10, which specifies the minimum number of extinguishers and the maximum travel distance allowed to access an extinguisher. Plant personnel expected to utilize the portable extinguishers have received appropriate training in their use in accordance with NMPC Corporate Policy for Employee Fire Training. These personnel include the fire brigade and all personnel qualified to serve as fire watches for hot work activities.

Fire Brigade Staffing and Equipment

A site fire brigade, consisting of at least five individuals, is on shift at all times. Each fire brigade member receives an annual physical examination to assure the capability to perform strenuous fire fighting activities. Personal protective equipment is available for each fire brigade member, which includes turnout gear, boots, gloves, hard hats and self-contained breathing apparatus. In addition, portable radios, portable lights, portable ventilation equipment and fire extinguishers are available for fire brigade use. Fire brigade equipment is included in the Emergency Preparedness equipment list which is subject to periodic surveillance per plant procedures. This provides assurance that all fire brigade equipment is maintained in operable condition and ready for use in a fire event.

Fire Brigade Training

There is a comprehensive fire brigade training program required by plant procedures. This training program includes initial and retraining requirements which are repeated at least once every two years. The following topics are presented to every fire brigade member prior to assignment to the fire brigade and at least once every two years thereafter:

- Indoctrination of the plant fire fighting plan with specific identification of each individual's responsibilities
- Identification of the type and location of fire hazards and associated types of fires that could occur in the plant
- The toxic and corrosive characteristics of expected products of combustion
- Identification of the location of fire fighting equipment for each fire area and familiarization with the layout of the plant, including access and egress routes to each area

- The proper use of available fire fighting equipment and the correct method of fighting each type of fire

- The proper use of communication, lighting, ventilation, and emergency breathing equipment

- The proper method for fighting fires inside buildings and confined spaces

The following topics are presented to the fire brigade leader and at least two fire fighters assigned to each shift prior to assignment to the fire brigade and at least once every two years thereafter:

- Training to understand the effects of fire and fire suppressants on safe shutdown capability

- Detailed review of fire fighting strategies and procedures as contained in the fire preplans

- Review of the latest plant modifications and corresponding changes in fire fighting plans

The fire brigade leader for each shift is trained in the following prior to assignment as the fire brigade leader:

- Competent to assess the potential safety consequences of a fire and advise Control Room personnel

- Incident command training to be knowledgeable in the direction and coordination of fire fighting activities

<u>Fire Brigade Practice</u>
All fire brigade members attend training sessions at the Niagara Mohawk Fire School at least once per year. This training provides experience in actual fire extinguishment and the use of emergency breathing apparatus through the use of hands-on structural fire fighting. This training exposes fire brigade members to the variety of fires which are anticipated within the environment of a nuclear power generating station. Specifically, props including the following fire scenarios are utilized during the live fire training evolutions: Class A combustibles (interior and exterior applications), energized electrical equipment, search and rescue of victims combined with fire suppression, oil-filled electrical equipment, flammable/combustible liquid spills, natural gas or propane, vehicles, fuel storage, chemicals, elevated or sub-surface incidents. All live fire training is performed with full personal protective equipment and self-contained breathing apparatus in use.

Fire Brigade Drills
Fire brigade drills are conducted in the plant on a quarterly basis so that each fire brigade shift can practice as a team. Plant procedures require each fire brigade member to participate in at least two drills per year to maintain their qualification on the fire brigade. As required by plant procedures, at least one unannounced fire drill for each shift fire brigade is performed per year. One drill per year is conducted on the backshift for each shift fire brigade. All drills are pre-planned to establish training objectives and are critiqued per plant procedure to determine the adequacy of the drill response. Unsatisfactory drill performance results in an additional drill within 30 days to determine whether corrective actions were appropriate. As part of the required triennial QA audit of the fire protection program, an unannounced drill is performed and critiqued by the independent fire protection consultant.

Fire Fighting Strategies
Pre-fire plans have been prepared for all plant fire areas. These plans contain information to assist the fire brigade and Control Room personnel in determining strategy alternatives, suppression equipment available, safe shutdown equipment which may be affected during a fire, smoke removal options, and access and egress paths available. These pre-fire plans are updated on a periodic basis as required by plant procedures and are used extensively as part of the fire brigade training program.

Fire Brigade Records
The Training Department maintains individual training records for each fire brigade member. These records are reviewed periodically to assure the Fire Protection Supervisor that all fire brigade members are receiving the appropriate level of training to allow continued assignment to the fire brigade. The minimum training that is required to be a member of the fire brigade is specified within plant procedures. Members who fail to meet the level of training required are removed from the fire brigade roster until their training is brought up-to-date.

4.8.4 Total Environmental Equipment Survival

Based on the review of available technical information relating to smoke damage, there does not appear to be a concern for operability of safe shutdown equipment outside the area of fire origin. Spurious or inadvertent operation of fire protection systems has been evaluated for its impact on safe shutdown equipment and operators have been trained and equipped to deal with safe shutdown actions. Therefore, the issue of total environment equipment survival is considered to represent a small risk.

Potential Adverse Effects on Plant Equipment by Combustion Products
This section addresses the Sandia Risk Scoping issue of smoke damage to electronic equipment outside the area of fire origin (i.e., equipment that is not already considered as damaged under the worst case assumptions of the Safe Shutdown Analysis). Only the short term effects of smoke damage are addressed here, that is, can the operators expect to be able to shut down the plant without experiencing additional equipment losses due to smoke

damage. The need to clean equipment to ensure its long term operability would still need to be addressed in the event of a significant fire.

The first step in addressing this issue was to perform a literature search at the National Institute for Standards and Technology's (NIST, formerly the National Bureau of Standards) Center for Fire Research library. This library features an electronic database permitting keyword searches of the fire protection research papers which have been collected for more than 20 years at the government's premier fire protection research facility.

The first thing evident from this literature survey was the scarcity of research dealing with the effects of smoke on electronic equipment. While there were more than 1000 articles on smoke, combining this keyword with electronics resulted in only four items dealing with both and none of these was germane to the practical resolution of the issue raised by Sandia. A more "relaxed" search for articles containing the keywords smoke and damage resulted in more than 70 potential research articles, however, a review of the title narrowed this list to less than 10, only three of which were actually related to the issue at hand.

As indicated below, none of the research looked at the short term operability of electronic equipment, instead it was focused on the long term operability and post-fire cleaning requirements. Another factor to keep in mind is that the research in this area is being driven (sponsored) by the telecommunications industry and not by insurance industry concerns over smoke-induced corrosion damage to other types of equipment. The circuitry in telecommunications facilities is much less robust than that in a power generation plant as witnessed by the clean room technology which is required in many of these facilities to keep out dirt and moisture.

One of the issues raised by Sandia with respect to smoke damage is that the halogen content of cable jacketing materials (whether or not they are fire retardant) is a significant concern. Research reported by O'Neill[35] indicates that <u>all</u> smoke is corrosive and that simple measurements of pH, or other acid measurements, will not provide a true picture of corrosion potential. He also emphasizes that tests should be run with the material exposed to fire temperatures to ensure that the species evolved reflect fire conditions and that the test object be remote from the burning material to ensure that the capability of the smoke to transport the corrosives to a remote point (i.e., away from the room of fire origin) be incorporated in the test. As with all of the other research, the authors do not identify a concern with immediate inoperability of electronic equipment but with the long term effects, i.e., corrosion which occurs long after the fire (if the electronic components are not cleaned in the first day or two).

Reagor[36] indicates that contamination levels below 200 micrograms per square inch do not represent a significant long term corrosion threat and they are easily (economically) cleaned to prevent this long term corrosion. Contamination levels between 200 and 600 micrograms per square inch represent a significant long term corrosion threat and although they are capable of being cleaned to prevent this long term corrosion, the economics decrease as the level of contamination increases or the time before cleanup increases. Above 600 micrograms per square inch, the contamination probably makes replacement more economical than cleaning.

The lack of a perceived short term inoperability threat from exposure of sensitive electronic equipment to smoke can be seen by examining one of the most recent proposals for a standard fire test (to determine the corrosivity of the smoke from prospective building materials). In May, 1992, Tewarson[37] proposed that threshold concentrations (to cause corrosion damage) be assessed by an exposure lasting 22 hours and storage of the exposed sample for up to another 40 weeks before determination of the amount of metal lost to corrosion.

Based on the literature review, and the articles cited above, it is clear that the smoke damage issue for telecommunications companies is long term operability, on the order of several days to weeks or more, rather than the short term period required to bring a nuclear power plant to a controlled shutdown. Furthermore, it must be stressed that the electronic equipment of concern in the telecommunications is much more susceptible to smoke corrosion damage than the motors, breakers and switches of concern in shutting down a power plant.

The potential threat for smoke damage causing inoperability of equipment remote from the fire area at NMP2 is further reduced by several plant design features (many of which are common to most nuclear power plants). These features include:

- Most of the more sensitive electronic equipment is in the Control Room which has a separate ventilation system which can maintain the Control Room under positive pressure relative to the rest of the plant. In the event of a Control Room fire which is of sufficient magnitude to cause evacuation, the plant can be shutdown by a remote shutdown panel which is electrically independent of the Control Room.

- The entire Control Building, and many other plant areas, are provided with dedicated smoke removal paths which ensure that the products of combustion will not traverse other plant areas to reach the exterior of the building. NMP2 pre-fire plans enable this equipment to be quickly identified and activated in the event of a significant fire.

- While there is no dedicated smoke removal system in the Reactor Building, the large volume of air in the structure ensures that smoke from a fire would be rapidly diluted. This dilution would serve to decrease the level of corrosives in the smoke and minimize any potential smoke damage to electronic equipment.

- In other plant areas without a dedicated smoke removal system, the smoke venting instructions in the pre-fire plans generally direct the fire brigade to use stairwells as the path to take smoke to the exterior. This would serve to minimize the potential for smoke damage in areas away from the area of fire origin.

- In addition, the actual pumps, motors, etc. required for achieving and maintaining shutdown have local controls which can be utilized if smoke exposure to control boards should eventually cause damage to some of the remote control circuitry.

Spurious or Inadvertent Fire Suppression Activation
The issue of spurious or inadvertent fire suppression causing inoperability of safe shutdown equipment was discussed within the NMP2 analysis of NRC Information Notice 83-41. The events reported in IN 83-41 are numerous but focus on the interaction between fire suppression systems and safety related equipment, particularly that equipment relied on to achieve and maintain safe shutdown. Some events are caused by inadequate design considerations, others by inadequate maintenance or testing procedures. The consequences of fire suppression system actuations have resulted in unit shutdowns. Of concern within this evaluation is the concurrent loss of a safe shutdown component and its redundant counterpart due to suppression system actuation.

Design considerations for fire protection systems at NMP2 include the interaction between the fire protection system and other systems or components within the subject areas. Examples are carbon dioxide systems in dense electrical cabling areas and halon systems in normally inhabited areas. Cable raceways in the vicinity of powerboards and other safety related equipment are protected primarily by fire retardant materials or automatic closed-head (wet pipe or preaction) water sprinkler systems rather than by open-head (deluge) water sprinkler systems. Other design features include floor drains and sumps, curbs, and pedestals to elevate equipment above the floor to prevent water intrusion from flooding. Water shields and baffles are installed in areas where the potential exists for water discharge to enter electrical equipment from above. Additionally, fire barrier penetration sleeves are installed in floors and extend above floor level to prevent leakage through the penetration in the event of water accumulations during fire suppression activities.

As part of the design of NMP2, Stone and Webster Engineering Corporation (SWEC) reviewed IN 83-41 Attachment 2 which delineated specific examples of events that may be precursors to more serious similar events. The SWEC review, documented in SWEC letter 9M2-14814 dated 9/26/83, addressed each of the concerns and modified plant design as appropriate to minimize the potential for similar events to occur at NMP2.

Operator Action Effectiveness
Procedure N2-SOP-78 and N2-OP-47 are in place which identify the steps necessary to achieve safe shutdown in the event of a fire. Operators have access to self contained breathing apparatus for use in the event of a need to access or pass through an area which may contain products of combustion.

In the event of a need to evacuate the control room, N2-SOP-78 delineates the actions necessary to achieve and maintain safe shutdown utilizing the remote shutdown system. Training on this procedure has taken place with operators required to accomplish safe shutdown.

4.9 USI A-45 and Other Safety Issues

IPE[1] Section 3.4.3 discusses and defines the systems/functions that support long term decay heat removal and their importance. This section supplements the IPE relative to the importance of fire hazards impact on this function. The following summarizes fire impact on the decay heat removal function in comparison to the IPE:

- The contribution to IPE core damage frequency due to loss of decay heat removal is approximately 9E-6/yr. The results of this analysis indicates that the contribution from fires is less than in the IPE.

- The only compartment judged to potentially have a core damage frequency greater than 1E-7/yr is the control room (Section 4.6). The frequency of core damage due to control room fires is estimated to be on the order 1E-6/yr.

- The risk from control room fires is judged to be dominated by fires that impact support systems. Station blackout, loss of injection and human unreliability in the short term to recover support systems and level control are judged to dominate. The frequency of a significant fire is low, the immediate concern is inventory control and operator response, and there is significant time to recover heat removal given inventory control success. For these reasons, the loss of heat removal contribution is less than the 1E-6/yr value.

Based on the results of the analysis in Section 4.6, the IPE is judged to reasonably represent the risk associated with loss of the decay heat removal function.

Other safety issues relative to fires are discussed in Sections 4.8.

5.0 High Winds, Floods, Transportation, and Nearby Facility Accidents

For the high winds, floods, transportation, and nearby facility accidents, hereafter referred to as "other hazards", portion of the NMP2 IPEEE, the methodology outlined in NUREG-1407[3] was used. This methodology is best described as a progressive screening approach. In this approach, each issue is evaluated in greater detail for each subsequent step of the analysis until it can be shown to be either low risk or a vulnerability. For each type of potential hazard, the evaluation requires, at a minimum, a review of the plant relative to the hazard, a review of changes since the issuance of the plant's operating license (OL), and a review of the plant against the 1975 Standard Review Plant (SRP)[7]. Per NUREG-1407, the scope of the analysis includes high winds, external flooding, and transportation and nearby facility accidents. These events are discussed in the following sections. In addition, other external events are considered, in less detail, in Section 5.4.

Overall, the analysis breaks down into eight tasks, the first three of which were summarized in the above paragraph. Task 1 requires the analyst to review available information regarding the plant design and licensing basis relative to the hazard under evaluation. Task 2 requires the analyst to extend the set of information above by considering changes since the issuance of the plant's OL. Specifically, the review should evaluate changes with respect to miliary and industrial facilities within 5 miles (~8 km) of the plant, onsite storage or other activities involving hazardous materials, transportation,and development that could affect the original design conditions. In addition, a plant walkdown is performed to identify any additional relevant information. In task 3, the analyst review the information obtained above relative to 1975 SRP criteria. If the plant conforms to the 1975 SRP criteria and no potential vulnerabilities are identified in task 2, the hazard is screened and is considered to pose a negligible risk.

If the hazard is not screened based on SRP criteria, then three types of detail analysis are considered. If the hazard can be screened by any of the three detailed analysis approaches, then it is considered a negligible risk.

The three detailed analyses are: task 4 - hazard frequency analysis, task 5 - bounding analysis, and task 6 - probabilistic risk assessment (PRA). In the hazard frequency analysis, the analysis considers the probability of the hazard occurring. If the event frequency can be shown to be less than 1E-5 per year with conditional core damage probability of 1E-1 per event, then the hazard can be screened. This amounts to showing that the hazard related core damage frequency is less than 1E-6 per year. If the hazard under review does not screen, then one of the other two detailed analysis approaches is used.

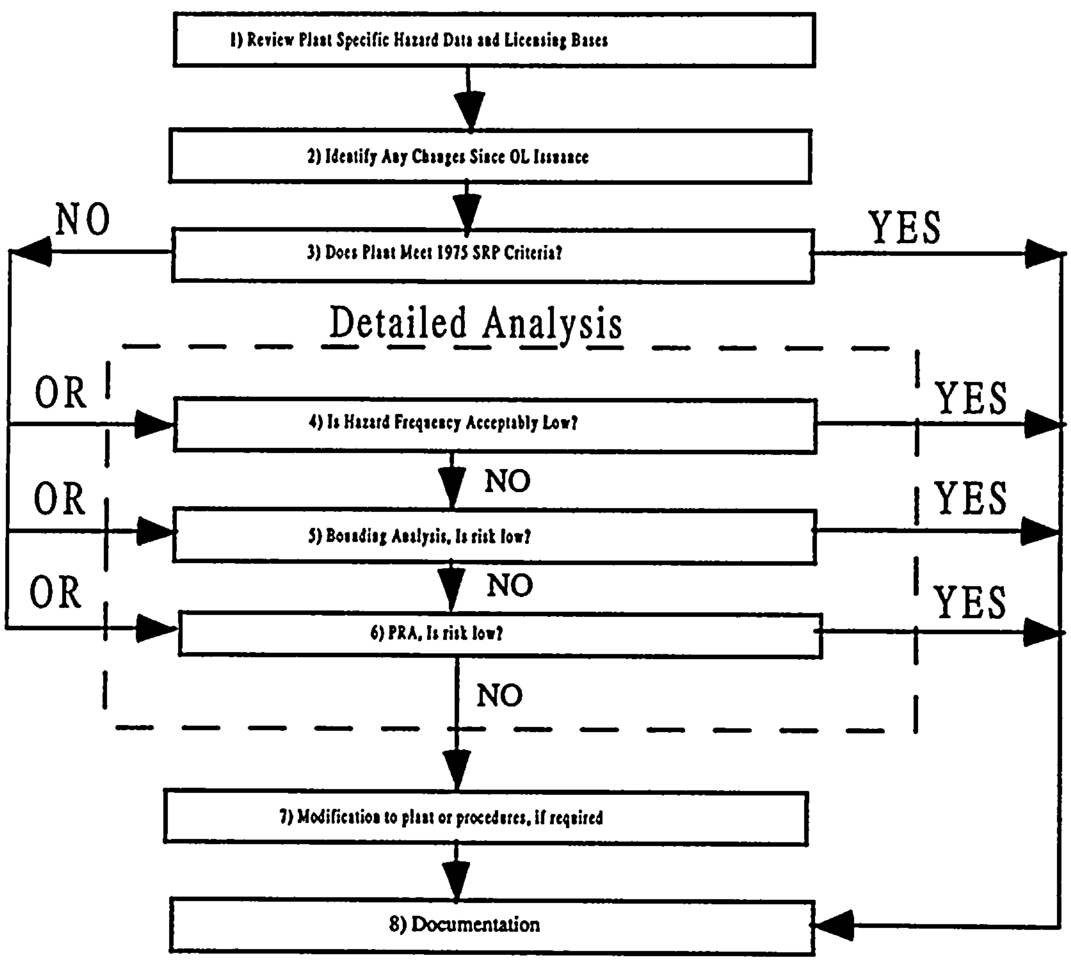
The second type of detailed analysis is called bounding analysis and it considers the consequence of the hazard. If it can be shown that the hazard could not result in core damage, then it can be screened as a negligible risk. If it cannot be screened, then PRA is considered.

In the PRA, detailed fault trees and/or event trees are developed to model the frequency of the event and the probability that the plant equipment and operators respond to mitigate the event prior to core damage. The approach to this type analysis is described briefly in Sections 2 and 3 of this report and in additional detail in both the NMP2 IPE[1] and NUREG/CR-2300[4].

Figure 5.0-1 shows a simplified representation of the approach for the others analysis. This figure was taken from NUREG-1407 and modified slightly. As shown in the figure, tasks 4 through 6 are optional tasks. One of the optional tasks, at a minimum, is used, at the discretion of the analyst, for any hazard that does not screen based on the SRP review. Two or three of the optional tasks may be used if the hazard is not screened. If the hazard can not be screened by the SRP review or any of the detailed analyses, then modification to the plant and/or procedures is considered in task 7.

The final task is documentation of the analysis. The remainder of this section describes the analysis and provides summary documentation of the analysis and results.

Figure 5.0-1 NMP2 Approach for Other External Hazards



5.1 High Winds

The high winds portion of the analysis considers the potential for tornados and other high wind phenomena to affect the plant. The effect could be in terms of direct interaction with structures or indirect interaction via wind generated missiles. The approach outlined above was used in the IPEEE evaluation of high winds.

5.1.1 Plant Specific Hazard Data and Licensing Basis

The NMP2 Safety Analysis Report (USAR)[6] provides information regarding the local climatic wind effect. Relevant information form this source is summarized below.

The local prevailing wind speed averages 10 miles per hour (MPH) in the westerly direction. The fastest-mile wind recorded at Hancock International Airport in Syracuse is 63 miles per hour at a height of 72 feet in October 1954. Speeds up to 73 miles per hour have been recorded in the vicinity of the more distant Rochester. Per input from the New York Power Authority[58] (NYPA), wind speeds of 73 mph have been recorded at the Fitzpatrick site. Fitzpatrick is located immediately to the east of NMP2.

During the period between 1951 to 1980, 14 tornadoes were reported in the 14,000 square miles surrounding NMP2. The two closest tornadoes were within 5.6 miles of the plant. Based on statistical analysis of these events, the USAR reports a 3.57E-5 per year probability of a tornado striking NMP2.

The design basis for protection against natural phenomena is

> *Structures, systems, and components important to safety are designed to withstand effects of the most severe natural phenomena, specific to the site, combined with appropriate normal upset and accident conditions to ensure that there is no loss of capability to perform safety functions. Historical data are utilized with appropriate margin for the specific geographical area in determining the effects of natural phenomena.*

With regard to high winds, NMP2 Category I buildings are designed to withstand a fastest-mile wind velocity of 90 miles per hour at a height of 30 feet and a recurrence interval of 100 years. Gust factors and resultant applied wind force is derived and applied to the evaluation of buildings at various height zones. The following table, based on USAR Table 3.3-1, shows the resulting dynamic wind pressure for Category I structures.

Table 5.1-1 DYNAMIC WIND PRESSURE FOR CATEGORY I BUILDINGS

Height Above Grade (ft)	Basic Wind Velocity Corresponding to Height (mph)	Dynamic Wind Pressure (psf)
0 to 50	90	26
50 to 150	115	42
150 to 400	145	66
400 to 600	175	95

Key equipment and structures, per USAR Table 3.2-1, are designed to withstand tornadoes with the following parameters:

- Maximum rotational velocity of 290 mph
- Maximum translational velocity of 70 mph
- Minimum translational velocity of 5 mph
- Maximum external pressure drop of 3 psi at the vortex
- Maximum rate of pressure drop of 3 psi/sec
- Radius of influence of 150 ft.

The maximum resultant wind velocity is 360 mph based on summing the maximum rotational velocity and the maximum translational velocity. This wind velocity is conservatively assumed to be constant over the height of the plant although velocity will vary along the height of the tornado.

Systems and components not designed to withstand tornadic forces will not effect the functioning of systems and components important to safety. Objects such as metal siding, roofing, roof decks, and parapets may blow off but will not cause significant missiles. Objects in non-Category I structures with the potential to become significant missiles, such as steel columns, beams, bracing and purlins, are designed to withstand tornadic forces and remain in place. However, they are located far enough away from important equipment to pose little threat should they collapse.

The following table, based on USAR Table 3.5-22, shows the barriers that protect important equipment from postulated missiles.

Table 5.1-2 MISSILE BARRIERS FOR NATURAL PHENOMENA AND TURBINE-GENERATED MISSILES

Protected Components	Missile Barrier
RCPB, ECCS, CRD and other safety-related equipment containment	Exterior reactor building wall, primary containment structure, internal structures
Main control room and related electrical, instrumentation, control, and ventilation equipment in control building	Control Building
Spent fuel pool	Reactor building wall below el 353' and 353' slab
Diesel generator-system	Diesel generator building
Service water pumps and piping	Screenwell service water pump room
Service water pump bay unit coolers	Service water pump bay - screenwell building
Standby gas treatment system	Standby gas treatment building
ECCS, MCCs, and other safety-related equipment	North and south auxiliary bay roof
HVAC, SWP valves, and related equipment	Auxiliary service building slab at el 261'

The following table, based on USAR Table 3.5-20, shows the postulated missiles used in design basis analysis. The upper portion of the reactor building is constructed of relatively lightweight sheet metal. It may blow off in high winds but it is not considered massive enough to form a missile(s) that will affect safety related equipment; including the fuel in spent fuel pool.

Table 5.1-3 SELECTED EXTERNAL MISSILES

Missile	Weight (lb)	Horizontal Impact Velocity (mph)
Wood plank, 4" x 12" x 12'	200	288
Steel pipe, 3-in diameter schedule 40, 10 ft long	78	144
Steel rod, 1-in diameter x 3 ft long	8	216
Steel pipe, 6-in diameter, schedule 40, 15 ft long	285	144
Steel pipe, 12-in diameter, schedule 40, 15 ft long	743	144
Utility pole, 13 1/2 in diameter, 35 ft long	1,490	144
Automobile, frontal area, 20 sq ft	4,000	72

5.1.2 Walkdown and Evaluation of Significant Changes Since OL Issuance

An NMP2 Walkdown[44] was performed to evaluate the significance of plant changes since the issuance of the Operating License (OL). With regard to high winds and tornadoes, NMPC IPEEE staff toured the facility with the mindset of reviewing issues that may affect the information in the above section. The following table shows the wind related observations along with a determination of significance and resolution.

Table 5.1-4 OTHERS WALKDOWN - WIND RELATED OBSERVATIONS

Observation	Significance/Resolution
Several large vehicles in proximity to Category I buildings	Vehicles are much larger than the front automobile section used in the missile evaluation. However, with regards to impact force, the greater mass is offset by a lower wind induced speed. Further, the impact area would be greater due to the larger size of the vehicle thus spreading the impact over a larger surface. In addition, the vehicles were of a transient nature which tends to limit the probability of related events.
Storage of miscellaneous material (Nitrogen compressed gas cylinders, trash barrels, etc)	These objects are within the size of missiles analyzed as per the above section. Their potential to cause damage to important material is judged to minimal.
EDG exhaust stacks (non-safety-related) could fail under high wind conditions	Per NMP2 USAR[6] Table 3.5-22 and NMP2 SER[48] supplement 4 page 3-3, the non-safety related exhaust stacks are unlikely to affect EDG operability even if damaged in a tornado.
Construction of several new non-safety related buildings was noted. Construction of these buildings occurred after issuance of the NMP2 OL.	Safety evaluations[45,46] for some of the buildings were reviewed and it was noted that there was no indication that the portions of the buildings that could cause significant missiles were designed to withstand tornadic forces and remain in place. As discussed above, the NMP2 USAR indicates that such objects are designed to remain in place. Deviation Event Report (DER) 2-95-0175 was written to identify this finding and initiate a process for resolving the discrepancy. However, this finding is judged to be of limited risk significance because, event without design intent, large objects, such as steel beams, are well anchored in order to support the building. Siding and other lightweight material may blow off but larger, i.e. more massive than those shown in Table 5.1-3, are unlikely to dislodge. More discussion of this issue is presented in the detailed analysis section below.
NMP1 Main Stack is not designed with withstand tornadoes and can reach some NMP2 structures if it falls	NMP1 stack can not reach critical NMP2 structures or equipment. Quantitative evaluation is shown in the Detailed Analysis section below.

5.1.3 SRP Criteria Review

Meeting SRP criteria for high winds requires that design meet General Design Criteria (GDC) 2[43] and GDC 4[47]. Section 3.1 of the NMP2 USAR describes the conformance with GDC and generally equates NMP2 design conformance with the GDC.

Sections 3.3.1, 3.3.2, 3.5.1.4, 3.5.1.5, 3.5.2, and 3.5.3 of the SRP provide the requirements necessary to meet GDC 2 and GDC 4 for high winds and tornados. The NMP2 Safety Evaluation Report (SER)[48] documents that NMP2 conforms to the applicable criterion. Some exceptions are noted where NRC has evaluated individual anomalies and determined that NMP2 meets the intent of applicable criteria.

The finding relative to new buildings and the NMP1 stack are possible exceptions. For completeness here, it is assumed that these issues are not able to be screened by the SRP criteria review step and detailed analysis is warranted to determine the risk significance of the issues and evaluate the potential for plant vulnerability.

5.1.4 Detailed Analysis

With respect to the possibility that large missiles dislodge from non-safety related buildings during a tornado, PRA can be used to quantify risk significance. This issue arises since it had not been demonstrated that newer site buildings were designed to have large members withstand a tornadic event. For a core damage to result, the following sequence of events must occur:

- Tornado (3.57E-5 per year, as discussed above)
- Significant missile(s) breaks away from non-safety building (0.5 assumed). Since the buildings are constructed as permanent buildings it is unlikely, even without design intent, that beams and bracing will break away.
- Missile(s) hits safety related structure and pierces shield (0.1 assumed). A missile(s), if generated, needs to strike a safety related building. The probability of a strike is not 1.0. In addition, there is design margin for missile shields such that missiles in excess of those in the Table 5.1-3 are not guaranteed to cause damage.
- The strike(s) causes core damage (1E-2 assumed) or fails equipment whose functionally redundant equipment subsequently fails (1E-2 assumed) (2E-2 total).

Multiplying the values in parentheses yields the overall sequence probability. In this case, the value is 3.6E-8 per year. A number of the above assumptions are judged conservative and the probability of core damage is clearly small (i.e., <1E-6 per year probability).

Regarding the NMP1 stack accident, a PRA evaluation can be performed. The NMP1 stack is a significant distance from NMP2. Per Figure 5.1-1, it can be seen that the NMP1 stack could damage the Hydrogen storage facility, the chiller building, and possibly the offgas building. The chiller and offgas buildings are of little safety significance and their inoperability will have little impact on the ability of the plant to mitigate the affect of the postulated tornado. Should the stack fall on the Hydrogen storage facility, an explosion could result. As can be seen from the figure, the storage facility is removed from the building and critical structures and equipment is effectively "shielded" by less critical structures and components. Core damage from this initiator would require the following events:

- Tornado (3.57E-5 per year)
- NMP1 stack falls (0.5 assumed)
- NMP1 stack falls on Hydrogen storage facility (3E-2). The 3E-2 value is derived by assuming that the stack is no more likely to fall in any particular direction. The storage facility occupies approximately 10° of the 360° target are of the stack. Thus, 10/360=3E-2. In addition, this takes no credit for the possibility that the stack may break somewhere near the midpoint thus limiting the distance for subsequent equipment damage.
- The Hydrogen facility explodes when the stack strikes (1.0 assumed)
- The blast causes core damage (0.1 assumed) or fails equipment whose functionally redundant equipment subsequently fails (1E-2 assumed) (0.11 total)

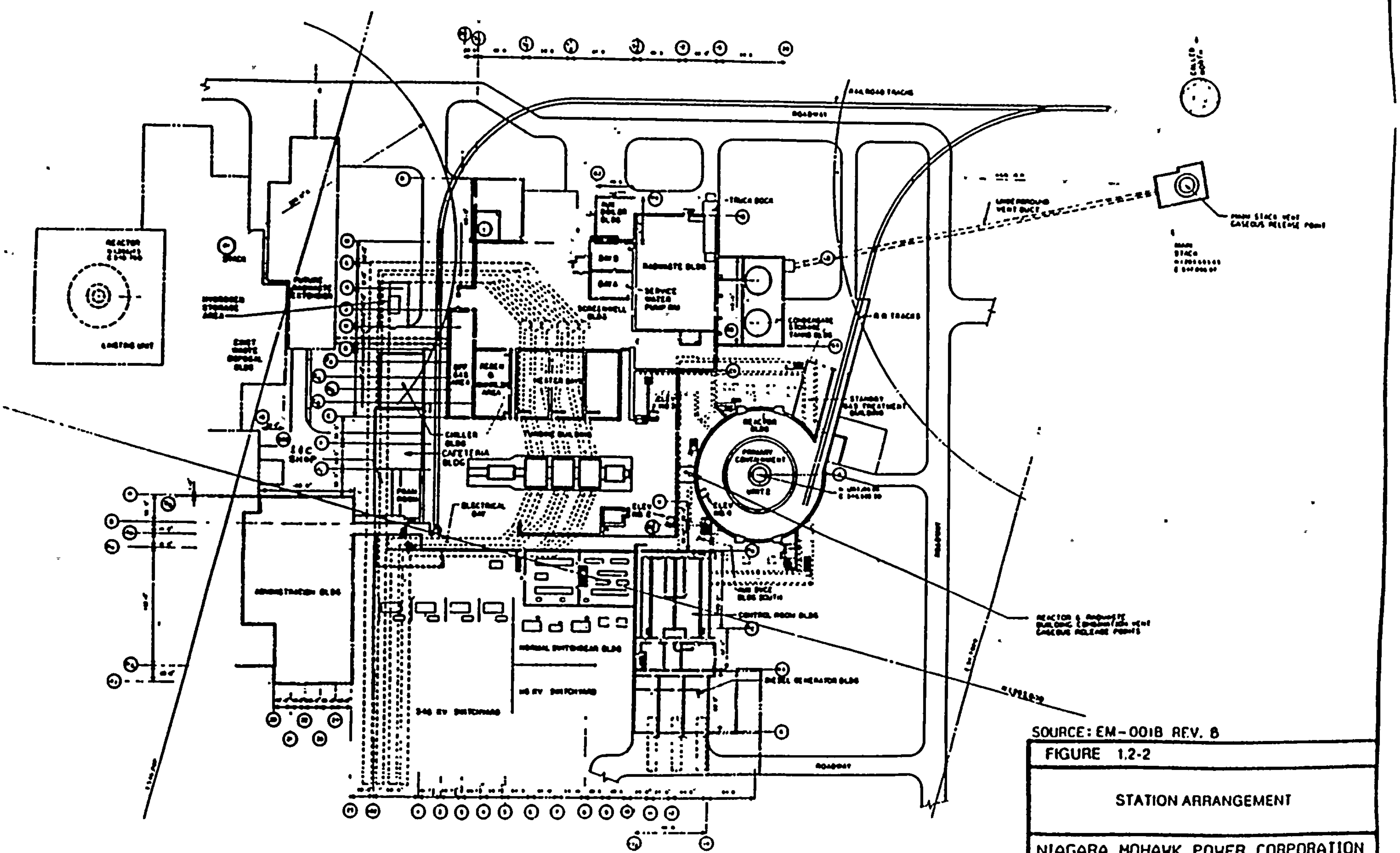
Multiplying the values in parentheses yields the overall sequence probability. In this case, the value is 5.88E-8 per year.

This calculation can be shown to be conservative by considering Branch Technical Position APCSB 9.5-1 "Guidelines for Fire Protection for Nuclear Power Plants." [59] and NFPA 50A "Standard for Gaseous Hydrogen Systems at Consumer Sites." [60] APCSB 9.5-1 indicates that plants should comply with NFPA 50A in order to protect safety related equipment from events related to gaseous hydrogen storage. NFPA 50A indicates that a separation of 25 feet between the outdoor hydrogen storage and other plant structures provides adequate protection. Since NMP2 meets this standard, the explosion hazard related to the bulk hydrogen storage is minimal. As such, the above-mentioned probability values can be considered conservative and the hydrogen storage risk can be considered negligible.

Table 5.1-5 shows the results of various industry high wind risk assessments[42]. The table shows noteworthy structures that contributed to the results. Since NMPC has discovered no noteworthy structures, it is reasonable to compare NMP2 with similar plants in Table 5.1-5. As such, it is reasonable to estimate that NMP2 high wind and tornado risk is on the order of 1E-8 per year. This comparison serves to confirm the above calculations.

Table 5.1-5
High Wind/Tornado Plant-Specific PRA Frequencies

Plant Name	Tornado Strike Frequency (Any Size) (/yr.)	High Wind Core Damage Frequency (/yr.)	Tornado Core Damage Frequency (/yr.)	Noteworthy Structures
Indian Point 2	1.00E-04	3.60E-05	<E-7	Unit 1 Superheater Stack Unit 2 DG Building Unit 2 Control Building
Indian Point 3	1.00E-04	1.30E-06	<E-7	
Limerick 1 and 2	2.30E-04	9.00E-09	<E-8	None
Millstone 3	1.87E-04	Low	<E-7	
Oconee 3		Low	<E-9	None
Seabrook 1 and 2	7.77E-05	<3.89 E-8	2.06E-09	None
Zion 1 and 2	1.00E-03	N.A	<E-8	
Arkansas Nuclear One-1	1.53E-03	1.16E-07	5.19E-06	DG Exhaust Stack Fails both DGs
Point Beach 1 and 2	5.38E-04	6.60E-07	3.30E-06	DG Exhaust Stack Fails both DGs
Quad Cities 1 and 2	1.04E-03	<<E-8	1.35E-07	310' Concrete Stack 4 kV, 480 V Switchgear Area Unit 2 Battery Room
St. Lucie 1	1.70E-04	<<E-8	<E-09	None
Turkey Point 3	1.70E-04	2.25E-05	1.73E-06	Unit 2 400' Concrete Stack DG Building DG Fuel Oil Transfer Pumps Switchgear Building Unit 3 RWST DG Fuel Oil Storage Tank CST Intake Pumps



SOURCE: EM-001B REV. 8

FIGURE 1.2-2

STATION ARRANGEMENT

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

USAR REVISION 5 OCTOBER 1993

5.2 Floods

The flooding portion of the evaluation deals with the potential for lake flooding, overland flooding, and/or heavy precipitation to damage critical plant equipment and structures. These effects could be in terms of water entering buildings from outside or in terms of heavy roof loads. Flooding due to plant internal sources, such as tank ruptures, was previously evaluated in the internal sources, such as tank ruptures, was previously evaluated in the internal floods portion of the IPE. The screening approach outlined above was used in this external flooding risk assessment.

5.2.1 Plant Specific Hazard Data and Licensing Bases

The NMP2 USAR provides information regarding local bodies of water, precipitation estimates, and related plant design information.

The principle body of water relating to NMP2 is Lake Ontario. There are no major streams or rivers within the drainage area that contains the site. Lake Ontario is approximately 193 miles long and 53 miles wide an area of approximately 7,340 square miles. It has a maximum depth of 802 feet and an average depth of 283 feet. The lake is fed by runoff from an approximately 27,300 square mile watershed. This provides approximately 36,000 cubic feet per second (cfs) supply to the lake. In addition, the lake is fed by the Niagara, Genessee, Oswego, Black, and Trent Rivers. Waters flow from the lake via the St. Lawrence River. During the winter the lake is seldom more than 25 percent ice covered.

Dams on the St. Lawrence River, controlled by the US Army Corps of Engineers, are used to control lake level. The NMP2 USAR reports a historical monthly average maximum lake level of 249.25 feet and an instantaneous maximum lake level of 250.19. The monthly average minimum lake level is 242.68 feet and the average lake level is 246 feet.

Maximum hourly precipitation recorded at the site is 2 inches. The maximum 24 hour amount is 6.34 inches. The maximum recorded 24 hour snowfall is 24.5 inches. The plant was designed using probable maximum precipitation (PMP) estimates from Hydrometeorological Report No. 33 (HMR-33)[49]. Roof support and roof drainage systems were designed based on HMR-33. Probable maximum flood (PMF) levels based on HMR-33 is 260.6 feet. This is below the 261' elevation where water can enter the interior of the plant. HMR-51[50] and HMR-52[51] were subsequently issued which indicated that higher precipitation than that reported in HMR-33 was possible. Subsequent analysis performed using these latest estimates[6] showed that the roofs of Category I building could support the additional precipitation. However, additional probable maximum flood analysis showed that the latest precipitation estimates lead to a flood level of 262.5 feet. The 262.5 foot value is based on superimposing the maximum regulated lake level, the maximum probable precipitation, and the maximum probable wave action. A review of the plant effect was performed based on this latest analysis and plant improvements were implemented. The NMP2 SER (Supplement 4) indicates that the NRC has reviewed NMPC's approach to HMR-51 and HMR-52 and finds it acceptable. However, this issue is discussed in additional detail below.

5.2.2 Walkdown and Significant Changes Since OL Issuance

An NMP2 Walkdown[44] was performed to evaluate the significance of plant changes since the issuance of the OL. With regard to external flooding, NMPC IPEEE staff toured the facility with the intent of reviewing issues that may affect the information in the above section. Independent of the walkdown, it was noted that Generic Letter 89-22[53] was issued which raised the issue of the significance of information in HMR-51 and HMR-52. This issue was considered by the walkdown staff and is discussed further below. The following table shows the external flood related walkdown observations along with a determination of significance and resolution.

Table 5.1-4 Others Walkdown - External Flooding Related Observations

Observation	Significance/Resolution
Roof scuppers and parapets were noted	These design features limit the potential for precipitation to collect on roofs
New building construction was noted. Potential to affect PMF.	Safety evaluations for the buildings[45,46] demonstrate that the buildings have a negligible effect on the potential for critical structure/equipment damage due to site flooding.
Doors to Control Building can allow water inflow below elevation 262.5'.	Doors had limited crack width but will allow water inflow during HMR-51 and HMR-52 PMF. NRC SER has reviewed the issue. This issue is discussed in the Detailed Analysis section below.

5.2.3 SRP Criteria Review

Meeting SRP criteria for flood protection requires that design meet GDC 2[43] and 10CFR100, Appendix A[52]. Section 3.4 of the NMP2 USAR describes the conformance with the GDC and 10CFR100 and generally equates NMP2 design conformance with the GDC and 10CFR100.

Section 3.3.4 of the SRP provides the requirements necessary to meet requirements for flood protection. The NMP2 SER[48] documents that NMP2 conforms to the applicable criterion. Some exceptions are noted where NRC has evaluated individual anomalies and determined that NMP2 meets the intent of applicable criteria.

The Generic Letter 89-22 issue was treated within the design basis of the plant per the NMP2 USAR and NRC SER. However, the risk significance of the issue can be considered within the scope of PRA. As such, although documented in the NMP2 SER, additional, i.e. detailed analysis of the issue is discussed below.

5.2.4 Detailed Analysis

Generic Letter 89-22 advised licensees to a condition whereby plants may experience greater precipitation than previously evaluated. This generic letter referenced Generic Issue 103 from NUREG-0933[54]. Both referenced HMR-51 and HMR-52. These evaluations increased previous estimates regarding the intensity of local precipitation. The revised HMR issues were evaluated and documented as part of NMP2 USAR and SER. However, it was noted that updated PMF evaluation has resulted in a PMF of 262.5'. This height is above the 261' elevation that would preclude water from entering the vital areas of the plant.

The USAR evaluation noted that the 262.5' level would be present for only a short duration and only a limited area for water entry is available between 261' and 262.5' of vital plant structures. As such, the issue was closed. However, for the IPEEE, it was noted that the electrical switchgear located on Elevation 261' of the Control Building are susceptible to flooding events.

Should water level reach 262.5' in the Control Building, the three emergency switchgears will almost certainly fail. These failures would result in a very high, i.e., approaching 1.0, conditional core damage probability. Thus, the probability of water reaching 262.5' in the Control Building could be important to plant risk. Quantitative data regarding the probability of an external flood reaching the revised PMF values is lacking. Historical data shows events which crested far below revised PMF levels. The HMRs and other industry sources are of little additional help. As such, it is clear that the probability of PMF level flooding is subject to great uncertainty. However, the risk significance of the flooding analysis can be demonstrated using the bounding analysis described above and in NUREG-1407.

The following considerations, developed to comprise a bounding analysis, when taken as a whole, demonstrate that the issue is of little risk significance:

- While subject to uncertainty, the probability of a PMF level flood can be qualitatively considered. The maximum instantaneous historical lake level is 250.19'. This value is significantly below the level which would comprise a PMF level event. Considering this margin, the efforts of the US Army Corps of Engineers, and the large floodplain surrounding the lake, it is considered very unlikely from a PMF level flood to develop. In addition, the PMF occurs when the highest lake level, worst case wind, and maximum precipitation are combined in one postulated event. Considering that each event is relatively unlikely on its own, the possible combination of the three events represents a scenario that is clearly of minimal probability. However, since this value can not easily and conclusively be shown, using currently available data and analysis, to be less than 1E-6 per year (or 1E-5 with a conditional CDF of 0.1), the following are presented to provide additional justification for the above-mentioned conclusion.

- The PMF, should it develop, would be an event that evolves over some large amount of time. Since this is the case, ample time would be available for plant operators to place the plant in a safe condition and perform recovery actions such as sandbagging the three control room doors, caulking outside and inside Control Building doors, installing pumps, and possibly reconfiguring plant electrical components. As such, the conditional core damage frequency, assuming the event occurs, is considered small.

- Per the USAR analysis, the three Control Building doors provide a limited capability to pass water and less critical lower elevations of the control building would fill before the more critical upper elevations.

With this in mind, the core damage frequency resulting from external flooding is considered negligible. As an additional point of reference, the core damage frequency for a Zion 1 and 2 can be considered[42]. These plants, although different design, are located on Lake Michigan, another "Great Lake", and are thus a viable comparison for NMP2. The CDF was determined to be 2E-8 per year. Contributors to this value included the emergency switchgear, an additional similarity with NMP2.

5.3 Transportation and Nearby Facility Accidents

This portion of the analysis considers the potential for transportation and nearby facility accidents to affect the plant. The effect could be in terms of direct interaction with structures or by causing operators to be incapacitated due to vapors of fumes. The approach outlined above was used in the IPEEE evaluation of Transportation and Nearby Facility Accidents.

5.3.1 Plant Specific Hazard Data and Licensing Bases

Only one manufacturing or industrial plant, Alcan Aluminum Corporation's Alcan Sheet and Plate Division is located within 8 km. of Unit 2. There are also two electrical power generation facilities, the J.A. Fitzpatrick Nuclear Power Plant operated by NYPA and Nine Mile Point Unit 1 operated by Niagara Mohawk Power Corporation, located within 8 km. of Unit 2. Sithe Energies, USA has recently completed construction of the Independence electrical generating station approximately 2 miles from the Nine Mile Point site. The Independence station is a natural gas fuel electrical generating plant. The implications of this construction on NMP2 are discussed in the detailed analysis section below.

The principle products of the Alcan Aluminum Corporation plant are aluminum sheet and plate. There are no chemical plants, refineries, military bases, o r underground gas storage facilities within 8 km. of the plant. In addition, no pipeline (except the Independence plant supply, discussed below) or fuel storage facilities lie within the 8 km. radius except those storage facilities associated with the Alcan plant, the FitzPatrick plant, and Nine Mile Point Units 1 and 2. The Pollution Abatement Services (PAS) hazardous waste site is located approximately 8 km west of NMP2. Nearly across the street from the PAS site is the NMPC Fire School. Neither of these sites is considered a threat to NMP2 due to the limited amount of materials present and the relatively large distance between them and NMP2.

The principle roadway within proximity of Unit 2 is Route 104, which passes 6.2 km. south of the plant and connects the City of Oswego and Mexico Village. Highway access to the Site is via two county routes, Route 1A to the southwest and Route 29 to the east. A private east-west road crosses the site and connects these two county routes.

One railroad company, Consolidated Rail Corporation (Conrail), transports freight in the vicinity of the plant. The closes rail line to Unit 2 is the Oswego-Mexico branch of Conrail located approximately 2.5 km from the Nine Mile Point Site. This branch line has daily service on demand and averages on train daily, fives days a week. A rail spur was constructed to serve Unit 2 during construction and operation of the plant.

The Oswego River passes within 11 km of Unit 2 at its nearest point and serves as a major route for waterborne commerce on Lake Ontario. Freight traffic statistics are maintained by the US Army Corps of Engineers. Totals for the river section from New York State Barge Canal Lock No. 8 to the port of the City of Oswego are the only statistics applicable for the nearest reach of river to the station. The port of Oswego, the easternmost port on Lake Ontario, is located approximately 11 km southwest of Unit 2 and provides a link with all ports on the Great Leaks and St. Lawrence River. Ships in normal commercial lanes bound to and from the Port of Oswego pass no closer than 11.3 km to the intake structures of NMP2.

Regular commercial air service is provided at the Clarence E. Hancock Airport, located 49.8 km southeast of Unit 2 near Syracuse, New York. The nearest flight corridor associated with this airport is 22.2 km from the Nine Mile Point Station. Light plant traffic is handled at the Oswego County Airport in the Town of Volney, approximately 19.3 km south of the Nine Mile Point Site. Lakeside Airstrip, a private facility which operates primarily as a maintenance facility with very little air traffic, is located along Route 176 approximately 10 km south of the Nine Mile Point Site. In addition, helicopter service is provided for local transportation between Hancock Airport and the site. The service involved approximately 1000 to 2000 feet west and south of the Reactor Building.

Description of Products and Materials

To identify hazardous materials regularly stored or used within 8 km of Unit 2, surveys were conducted of industrial firms, pipeline companies, and distributors that might be expected to handle toxic chemicals or explosives. Hazardous materials storage or used by industries or distributors in the vicinity of the station are summarized in Table 5.3-1.

Waterborne commerce accounts for approximately 1.2 million tons of cargo transported on Lake Ontario during 1978. The nearest passage of commercial vessels to Unit 2 occurs when navigating to and from the City of Oswego harbor. The Port of Oswego Authority indicates that none of the hazardous materials listed in Table 5.3-1 have been transported on Lake Ontario, either originating at or destined to the Port of Oswego. Instead, all industries reported receiving hazardous material shipments via U.S. Highway 104 and County Route 1 by truck.

Explosions

Based on a comprehensive survey of industries within a 8 km radius of Unit 2, the nearest highway on which explosive materials can be transported is Route 104, which is a distance of abut 6.2 km from safety-related structures. This separation distance far exceeds the safe distance for truck traffic prescribed in Regulatory Guide 1.91.

In discussions with Conrail, it was determined that no explosive or flammable materials are transported to the Oswego terminal on the rail line between Oswego and Mexico, New York. In any event, the distance from this rail line to Unit 2 is much greater than the safe distance for rail traffic given in Regulatory Guide 1.91.

Since the nearest commercial shipping lanes on Lake Ontario are more than 10 km from Unit 2, potential explosions on a ship or barge are not considered a design basis event. this distance is well beyond the radius of the peak indicadent pressure of 1 psi as given in Regulatory Guide 1.91.

Therefore, according to guidance contained in Regulatory Guide 1.91, explosions on nearby transportation routes are not considered design basis events due to the separation distances of potential sources of explosions from Unit 2.

Flammable Vapor Clouds (Delayed Ignition)

Propane stored at the James A. FitzPatrick plant is the only potential source of a flammable vapor cloud that might affect the Unit 2 site. Approximately 3,785 1 (1,000 gallons) of propane at the James A. FitzPatrick plant is stored about 700 miles from the Unit 2 Containment Building. An analysis has been performed to assess the potential for a 1-psi overpressure occurring at the Unit 2 Containment Building as a result of the delayed ignition of a flammable vapor cloud of propane. (A 1-psi overpressure is that pressure below which no significant damage to critical plant structures is expected, as determined by the US Nuclear Regulatory Commission in Regulatory Guide 1.91, "Evaluations of Explosions Postulated to Occur on Transportation Routes Near Nuclear Power Plants.")

The results of this analysis indicates that the delayed ignition of the puff or plume release from the propane tank at the Fitzpatrick station will not cause a 1-psi overpressure to reach the Unit 2 Containment Building.

Potential Sources of Toxic Chemicals

According to Regulatory Guide 1.78, both on site and off site potential toxic gas hazards must be considered. Any toxic substance that has the potential to form a toxic vapor cloud or plume after release to the environment and is stored on site in the quantity greater than 45 kg must be evaluated. Off site sources to be evaluated include stationary facilities and frequent transportation of toxic substances (truck, rail, and barge) within 8 km of the site. (Frequent shipments are defined as exceeding 10 per year for truck shipments, 30 per year for rail shipments, and 50 per year for barge shipments).

For the Nine Mile Point Site, sources of potential toxic chemical hazards include chemicals stored on site, as well as four stationary and two transportational sources within 8 km of the site. Table 5.3-1 lists the chemicals associated with each source along with their quantities and distances from the Unit 2 Control Room air intake. The three stationary sources include the James A. FitzPatrick plant, the Alcan Rolled Products Division, Oswego Wire, Incorporation, and Unit 1. One transportation source of possible hazardous materials is truck traffic along Route 104, which passes within 6.2 km of the Site. The second transportation source is the railroad line between Oswego and Mexico, New York. Discussions with Conrail indicate that on an average, only one hazardous chemical shipment during an 18-month period passes throughout he Oswego terminal. Traffic on a spur to the Site is not frequent enough (<30 per year) to warrant consideration.

The effect of an accidental release of each of the chemicals described in the previous section on Control Room habitability is evaluated by calculating vapor concentrations inside the Control Room as a function of time following the accident. This calculation is performed using the conservative methodology outlined in NUREG-0570 and utilizing the assumptions described in Regulatory Guide 1.78.

The results of the analysis indicates that none of the toxic chemicals evaluated have the potential to incapacitate the Control Room operators.

<u>Fires</u>

The production of high heat fluxes and smoke from fires at industrial or storage facilities, oil and gas pipelines, transportation routes, or homes in the Site vicinity does not present a hazard to the safe operation of the plant due to the distance of these potential fires from the site. The nearest truck route (Route 104) passes the site at a distance of about 6.2 km from the plant. There are no known regular shipments of flammable materials on Route 104 with the exception of possible local gasoline deliveries. The nearest residence is approximately 1.6 km from the site.

The site is sufficiently cleared in areas adjacent to the plant that forest or brush first pose no safety hazards. On site fuel storage fires do not jeopardize plant safety since these facilities are designed in accordance with applicable fire codes.

<u>Collisions with Intake and Discharge Structures</u>

Oswego Harbor is located approximately 12 km southwest of the intake structures. The intake structures are located approximately 1000 feet off shore in a water depth of at least 10 feet at the minimum controlled lake level.

If a barge should drift or break loose in the shipping lane, the distance of structures from that lane should provide sufficient maneuvering area for retrieval. In the case where a ship or barge should break up, any non-floating load would sink before reaching the intake or discharge structures. The location of these structures, approximately 6 miles to the nearest commercial shipping lane, minimizes the potential for being struck by passing commercial traffic and their depths minimize the potential for damage by any pleasure craft that may frequent the area.

In the unlikely event that a ship or barge were to collide with and completely incapacitate one of the intake structures, station safety would not be jeopardized because there are two intake structures, each one independently connected to the on shore screenwell and each one sized to individually provide sufficient safe shutdown cooling.

Liquid Spills

No oil and liquids that may be corrosive, cryogenic, or coagulant are stored at, delivered to, or transported through the area of the intake structure in Lake Ontario. All oil and liquids used at Unit 1 and the James A. FitzPatrick plant are transported by truck or rail. All oil and liquids that may be corrosive, cryogenic, or coagulable, which are transported within the 8 km radius, are moved on land. There is at most an extremely remote possibility of occurrence of liquid spills in the area of the intake structures, originating from land-based storage or transport. Service water is drawn in at low velocities through the sides of the intake structures. These provisions prevent the formation of vortices. Therefore, surface spills of liquids with sufficient density to reach the intakes must pass the region of induced turbulence and would be subject to dilution effects.

Any accidental liquid spills to Lake Ontario would be further diluted because of the distance between the origin of spills from either commercial shipping or land-based transport, and the intake structures. Liquids from land-based spills would have to travel a relatively great distance to reach the intake structures and would be subject to dilution during transport. Any liquid spills originating during common commercial ship transport would have to travel approximately 10 km to reach the intake location. Due to the combined effects of the submerged intake structures' design and the distance between intake structure location and origin of the potential liquid spill, the risk of entrainment of any significant quantities of oil, or corrosive, cryogenic, or coagulable liquids by the intake structures is negligible.

Airplane Crashes

The nearest air corridor is approximately 22.5 km east of the site. There are only two airfields between the 8 km and 24 km radii of the site; the Lakeside Airport and Oswego County Airport are about 12 km and 19 km south of the Site, respectively. The aircraft approaches to these airports are not near the plant site. The general aviation movements at these airports total approximately 1,460 per year and 19,900 year, respectively. The annual movements are below the critical number at which a probability analysis for aircraft accidents would be required according to Regulatory Guide 1.70. Therefore, the probability of aircraft crashing into the Site is considered to be remote, and airplane crashes need not be considered design basis events.

Similarly, for helicopter operations to and from the site, the probability of a helicopter crash resulting in radiological releases in excess of 10CFR100 guidelines has been conservatively estimated[61] to be approximately 1×10^{-6}, using the methodology of NRC Standard Review Plan 3.5.1.6. In accordance with Standard Review Plan 2.2.3, additional qualitative arguments could be made which would lower this probability to less than about 10^{-7} per year. This satisfies the requirements of Regulatory Guide 1.70 such that helicopter crashes need not be considered as design basis events.

Table 5.3.1

Sources of Toxic Chemicals Within 8 KM of Unit 2 Site

Chemical Location	Chemical	Amount (g)	Distance to Intakes (m)
James A. Fitzpatrick Plant	N_2 H_2SO_4 CO_2 Propane Halon 1301	0.305×10^8 0.346×10^8 1.18×10^7 0.221×10^7 0.260×10^7	620 620 620 620 620
Alcan	Cl_2 Propane N_2 HCL CO_2	0.181×10^7 0.363×10^8 0.227×10^8 0.226×10^7 0.535×10^8	4,990 4,990 4,990 4,990 4,990
Route 104	HCl N_2 CO_2	0.542×10^7 0.183×10^8 0.272×10^7	5,470 5,470 5,470
Nine Mile Point Unit 1	N_2 CO_2 H_2SO_4 HCL Halon 1301	0.443×10^8 0.907×10^7 0.114×10^7 0.454×10^5 0.227×10^6	290 265 290 290 290
Nine Mile Point Unit 2	CO_2 Halon 1301 N_2 H_2SO_4	0.118×10^7 0.113×10^6 0.671×10^8 0.159×10^9	33 45 46 146
Oswego Wire Incorporated	Isopropyl Alcohol N_2 Propane H_2SO_4 HCL	0.330×10^5 0.525×10^5 0.947×10^5 0.750×10^5 0.182×10^4	7,080 7,080 7,080 7,080 7,080

+ The new Independence Station is discussed below

5.3.2 Walkdown and Significant Changes Since OL Issuance

A walkdown was impractical due to the nature of the potential risk. Surveying the Alcan plant, barge traffic, etc., was not considered necessary for this scope of work. However, a review of potential issues is performed for every USAR update per procedure NLI-FSAR-01, Revision 0. This review recently led to the determination that a local natural gas fuel electrical generating plant had been constructed and became operational recently. The principle concern with this plant is the construction of a natural gas pipeline within approximately 2 miles of the plant. This issue is discussed in more detail below.

5.3.3 SRP Criteria Review

The NMP2 USAR and SER document NMP2 compliance with the SRP regarding nearby industrial and transportation events. However, these documents do not mention the Independence plant. As such, this issue will be treated in the detailed analysis section below.

5.3.4 Detailed Analysis

The Sithe Energies, USA natural gas fueled electrical generating station construction included a natural gas pipeline within approximately 2 miles from NMP2. The explosion hazard created by this gas pipeline can be evaluated using bounding analysis as discussed above and in NUREG-1407.

NMPC calculation 94-071[55] evaluated the consequences of a postulated break in the Sithe natural gas pipeline. The calculation assumed a complete severance of the pipeline with a ground level release at sonic velocity at the point closest to NMP2. The maximum resulting pressure effect on NMP2 due to the explosion is less than 1 psi. As such, the postulated explosion would not cause the failure of safety-related structures at NMP2.

The above-mentioned postulated break, and lower magnitude explosions, would likely lead to a loss of offsite power (LOSP) event with degraded potential for offsite power recovery. However, since the pipeline is located in a remote area, explosion probability is considered to be a negligible contributor to LOSP frequency.

The chemical storage at the Independence station was not explicitly polled for this evaluation. It is assumed similar, other than natural gas noted above, to NMP1, NMP2, and Fitzpatrick. Given the additional distance to the Independence station, risk from chemical storage and use is considered negligible. Additional transportation to and from the new plant and considerations with regard to flammable vapor clouds are similarly considered negligible.

5.4 Other External Hazards

The risk significance of other external events is discussed in Table 5.4-1.

TABLE 5.4-1 SUMMARY OF RESOLUTION OF OTHER EXTERNAL EVENTS			
Description of External Event	**SRPs Applicable to NMP2 (From NUREG/CR-5042)**	**Summary of NRC Resolution (From NUREG-1407)**	**Conclusion for NMP2**
Lightning	[No SRPs are cited in NUREG/CR-5042 as being relevant to the assessment of this initiating event]	The NRC has concluded that the probability of a severe accident caused by lightning (other than one due to loss of offsite power) is relatively low and further consideration of lightning effects should be performed only for plant sites where lightning strikes are likely to cause more than just loss of offsite power or a scram (e.g., degradation of instrumentation and control systems).	NMP2 lightning protection features ensure that the site strike frequency with severe consequences is relatively low. Initiating events modeled in the IPE such as loss of offsite power and loss of a divisional AC power division are believed to envelope the frequency and consequences of potential lightning impacts on the plant.
Severe Temperature Transients (Extreme Heat, Extreme Cold)	[No SRPs are cited in NUREG/CR-5042 as being relevant to the assessment of this initiating event]	The NRC has concluded that severe temperature transient events do not have to be considered in the IPEEE because the most significant effects (i.e., slow degradation of the ultimate heat sink and loss of offsite power), are generally unimportant from a risk perspective or ar already treated in the IPE.	The NMP2 IPE considered the impact on plant risk from a loss of offsite power initiating event, regardless of its cause. NMPC agrees that the capacity reduction in the ultimate heat sink and other impacts would tend to be a slow process allowing time for proper actions. Temperature transient initiating events need not be addressed in the NMP2 IPEEE, as recommended by the NRC.

TABLE 5.4-1 SUMMARY OF RESOLUTION OF OTHER EXTERNAL EVENTS			
Description of External Event	**SRPs Applicable to NMP2 (From NUREG/CR-5042)**	**Summary of NRC Resolution (From NUREG-1407)**	**Conclusion for NMP2**
Severe Weather Storms	SRP 2.4.5 Probable Maximum Surge and Seiche Flooding SRP 2.4.7 Ice Effects	The NRC has concluded that the most significant effect of severe weather storms is the potential for causing a loss of offsite power event. However, this event is considered in the IPE; therefore, the NRC has stated that severe weather events do not have to be evaluated in the IPEEE.	The NMP2 IPE has evaluated the risk associated with loss of offsite power events; therefore, the potential risk associated with severe weather storms need not be evaluated in the IPEEE.
External Fires (Forest Fires, Grass Fires)	[No SRPs are cited in NUREG/CR-5042 as being relevant to the assessment of this initiating event]	The NRC has concluded that the effects of fires occurring outside the plant site boundary (i.e., causing a loss of offsite power and isolation of ventilation), have been evaluated during operating license review against sufficiently conservative criteria. Therefore, the NRC has stated that these events do not need to be reassessed in the IPEEE.	The effect of a forest fire on the offsite electrical power system was not identified as a significant contributor to the frequency of Loss Of Offsite Power in the NMP2 IPE. Additionally, other effects of fires occurring outside the plant site boundary (i.e., isolation of ventilation and control rod evacuation), have been evaluated during operating license review. Therefore, it is judged that this event poses no significant risk to the safe operation of NMP2; and is not considered in the IPEEE.

TABLE 5.4-1 SUMMARY OF RESOLUTION OF OTHER EXTERNAL EVENTS

Description of External Event	SRPs Applicable to NMP2 (From NUREG/CR-5042)	Summary of NRC Resolution (From NUREG-1407)	Conclusion for NMP2
Extraterrestrial Activity (Meteorite Strikes, Satellite Falls)	[No SRPs are cited in NUREG/CR-5042 as being relevant to the assessment of this initiating event]	The NRC has concluded that the probability of a meteorite strike or a satellite fall is very small (<1.0E-9 reactor per year). Additionally, the NRC has stated that this event can be dismissed on the basis of its low initiating event frequency.	Based on the NRC's direction in NUREG-1407, the NMP2 IPEEE does not consider the effect of extraterrestrial activity to be risk significant.
Volcanic Activity	[No SRPs are cited in NUREG/CR-5042 as being relevant to the assessment of this initiating event]	The NRC has concluded that those sites that are located in the vicinity of active volcanoes should assess the impact on plant risk posed by volcanic activity.	NMP2 is not located near a volcano; therefore, it is judged that risk posed to safe plant operation from a volcanic initiating event is negligible.

6.0 Licensee Participation and Internal Review Team

As with the IPE, NMPC believes that the maximum benefit from the IPEEE is derived when a significant investment of in-house resources is applied. NMPC has been involved in all aspects of IPEEE preparation and review. Section 6.1 shows the organization of the IPEEE development team and Section 6.2 shows the organization of the IPEEE review team. Sections 6.3 and 6.4 summarize the review process.

6.1 IPEEE Program Organization

The NMP2 IPEEE team was comprised of NMPC staff and contractors. The following table summarizes the IPEEE team and shows the areas of involvement for each team member.

NMP2 IPEEE Team

Team Member	Organization	Area of Responsibility
NMPC Staff		
Robert F. Kirchner	Analysis	Project Manager, PRA Support (Fire, Seismic), Others Analysis, Fire Review
L.D. "Kass" Kassakatis	Analysis	PRA Support (Fire, Seismic, Others), Fire Analysis, Others Review
Steven D. Einbinder	Analysis	Fire Analysis
Gaines E. Bruce	Mechanical Design	Fire Analysis
Joseph F. Cushman	Structural Design	Seismic Analysis
Alfred N. Issa	Structural Design	Seismic Analysis
Carmen R. Agosta	Structural Design (U1)	Seismic Analysis
Francis H. Feng	Analysis	Seismic Analysis
Peter E. Francisco	Analysis	Fire Analysis, Seismic Analysis, Others Review
Consultants		
James H. Moody	Independent	Lead Consultant, PRA Support, Fire Analysis, Others Review
Thomas J. Casey	Independent	PRA Support, Fire Analysis, Seismic Analysis
Walter Djordjevic	Stevenson and Associates	Seismic Analysis
Tsi-ming Tseng	Stevenson and Associates	Seismic Analysis
Todd P. Mairs	Independent	Others Analysis
Robert C. Beller	Pacific Nuclear	Fire Analysis
Marvin D. Fetterman	Vectra Technologies	Seismic Analysis

The following table shows the nature of the review provided within the IPEEE Team. The IPEEE team review was viewed as important for a number of reasons:

- IPEEE Team review reduces the reliance on the Independent Review Team
- Because of the limited specialties involves in IPEEE, in many cases the IPEEE team relied on all cognizant NMPC staff; thus limiting the pool of available Independent Inhouse Reviewers
- Provided more timely feedback on the analysis
- Provided more opportunity to understand the inter-relationship between various IPEEE analysis tasks.

IPEEE TEAM PREPARERS/REVIEWERS

IPEEE Section	IPEEE Team Preparers	IPEEE Team Reviewers
3.1 Seismic Margins Method 3.1.1 Review of Plant Information, Screening, and Walkdown	See Section 3.1.1	NA
3.1.2 Systems Analysis	T. J. Casey J. H. Moody	L. D. Kassakatis R. F. Kirchner Marvin Fetterman Joseph Cushman
3.1.3 Analysis of Structure Response	Joseph Cushman Tsiming Tseng Walter Djordjevic	R. F. Kirchner J. H. Moody
3.1.4 Evaluation of Seismic Capabilities	Carman Agosta Joseph Cushman Walter Djordjevic Francis Feng Marvin Fetterman Tsi-ming Tseng Al Issa	R. F. Kirchner J. H. Moody
3.1.5 Analysis Containers Response	T. J. Casey J. H. Moody	R. F. Kirchner L. D. Kassakatis Walter Djordjevic
3.2 Seismic PRA	J. H. Moody	R. F. Kirchner Walter Djordjevic
3.3 USI A-45, GI-131, and Other Seismic Safety Issues	T. J. Casey J. H. Moody	R. F. Kirchner L. D. Kassakatis Walter Djordjevic
4.1 Fire Hazard Analysis	Bob Beller G. E. Bruce	S. D. Einbinder R. F. Kirchner J. H. Moody
4.2 Review of Plant Information & Walkdown	Bob Beller G. E. Bruce	S. D. Einbinder R. F. Kirchner J. H. Moody
4.3 Fire Growth & Propagation	G. E. Bruce	S. D. Einbinder R. F. Kirchner J. H. Moody

IPEEE TEAM PREPARERS/REVIEWERS

IPEEE Section	IPEEE Team Preparer(s)	IPEEE Team Reviewer(s)
4.4 Evaluation of Component Fragilities & Failure Modes	J. H. Moody	T. J. Casey S. D. Einbinder R. F. Kirchner
4.5 Fire Detection & Suppression	S. D. Einbinder	G. E. Bruce R. F. Kirchner J. H. Moody
4.6 Analysis of Plant Systems, Sequences & Response	T. J. Casey L. D. Kassakatis J. H. Moody	G. E. Bruce S. D. Einbinder R. F. Kirchner
4.7 Analysis of Containment Performance	T. J. Casey J. H. Moody	S. D. Einbinder R. F. Kirchner L. D. Kassakatis
4.8 Treatment of Fire Risk Scoping Issues	S. D. Einbinder	G. E. Bruce T. J. Casey R. F. Kirchner
4.9 USI-45 and Other Safety Issues	T. J. Casey J. H. Moody	S. D. Einbinder R. F. Kirchner L. D. Kassakatis
5 High Winds, Floods, and Others	R. F. Kirchner	J. H. Moody L. D. Kassakatis P. E. Francisco

6.2 Composition of Independent Inhouse Review Team

The following individuals comprised the internal review team.

NMP2 IPEEE Independent Inhouse Review Team

Team Member	Organization
Patrick J. O'Brien -- Lead Reviewer	Independent Safety Engineering Group
James A. Snizek	Technical Support
Jay S. Woodruff	Training
James G. Poindexter	Operations
Michael D. Jones	Engineering - Plant Evaluation
Joseph M. Thuotte	Licensing
Everett Homer	Quality Assurance

The above individuals were directed to focus their review on their specific areas of responsibility/expertise. For example, Jay Woodruff is involved in the fire protection program. As such, he was not asked to review Section 3 (Seismic). Overall, the entire IPEEE was reviewed even though each reviewer did not review the entire submittal.

In addition, the inhouse review team was supplemented by an external consultant. Harry Johnson, Programmatic Solutions, was contracted as an independent peer reviewer of the seismic portion of the IPEEE. He was not involved in the preparation of the analysis and reviewed the program when the technical analysis was complete.

Further, since the Fitzpatrick Nuclear plant is immediately to the east of NMP2, a draft of the NMP2 IPEEE was provided to the New York Power Authority (NYPA) for review and comment. The review was performed by John Bretti and comments were recieved, and encorporated, on Section 5 ("other" hazards).

6.3 Areas of Review and Major Comments

Each portion of the analysis was reviewed by at least one IPEEE team reviewer and an independent reviewer. The results of the reviews were generally in the form of conversations, marked-up sections of the IPEEE, and memorandums. None of the comments by the independent review team would be characterized as major; where a major comment was defined as one that affected technical results. Overall, comments could be characterized as grammatical or requiring clarification of technical issues. In particular, the reviewers typically requested additional discussion to make aspects of the study clearer to a reader that was not part of the IPEEE team. Individually describing these numerous comments in this section is unwieldy.

6.4 Resolution of Comments

Comments were generally input directly into the study and reviewed with the commenter. None of the comment resolutions were challenged by the Independent Inhouse review Team.

7.0 Plant Improvements and Unique Safety Features

Performing the IPEEE (an external events risk assessment) leads to a unique perspective on the plant under study. Section 7.1 discusses NMP2 features that were noted to be of particular interest during the study. Improvements identified during the study that resulted in specific improvement initiatives are discussed in Section 7.2. In addition to these initiatives, the study developed some insights that are discussed in Section 7.3. These insights for a number of reasons did not result in immediate action, but will continue to be studied by NMPC and as more information and research becomes available specific action may be initiated.

7.1 Unique Safety Features

Some interesting design features were identified during the IPEEE and are summarized below:

- Spatial Considerations
  The observation from the IPE that spatial arrangement and separation of safety divisions appears very good was confirmed by the IPEEE. Although both safety divisions come together at the main control boards in control room, even the separation here was good. In all other cases, it was excellent. The design also limited the potential for a fire to impact both offsite power and an emergency diesel power source which significantly limited the risk from fires.

- Control Complex Design
  This is related to spatial arrangement and separation discussed above. The design of the control complex, where nonsafety and both divisions of safety cables come together, significantly limits the risk from control room and relay room fires. The design of the control complex includes steel floor sections, termination cabinets, and panels[40]. The steel floor sections have fire detection and Halon suppression, and are designed to prevent fires from initiating, prevent propagation in the unlikely event of a fire, and allow easy access for quick suppression of fires. Floor sections are designed to limit the flow of air and exhaust gases by sealing all penetrations. This limits oxygen and eliminates air flow, thus preventing a fire from starting. The termination cabinets contain only cables, thus the frequency of a fire should be less than the frequency of fires in electrical panels in the control and relay rooms which contain relays, lights, and other electrical equipment. All termination cabinets have bays (typically 4) that are separated by 3/16 inch steel plate. Each bay has a smoke detector. All cables were tested in accordance with IEEE 383. TEFZEL insulated cables are used which have been proven by test to be difficult to ignite and are non propagating. Smoke generation is also insignificant. Generally, electrical separation criteria does not allow Division I, II, III, or non Divisional cables within the same floor section or termination cabinet section.

- Automatic Fire Detection and Suppression
  This feature allowed some critical cable spreading and switchgear areas to be screened out. Thus, this feature in some critical areas both reduces risk from fires and simplified the fire modeling analysis requirements during the study.

- Seismic Design
  The seismic capacity of NMP2 structures, systems, and components was found to be high. This in combination with a relatively low seismic hazard frequency leads to low seismic risks. Recognizing the conservatism in design, the analysts were able to utilize a 0.5g screening criteria with minor impacts on the analysis. The higher screening value with EPRI and NRC hazards, and the IPE, enabled the risk of seismic events to be quantified.

7.2 Plant Improvements

A number of benefits were derived from the IPEEE. An appreciation of the range of severe accidents that could occur at NMP2 now includes external hazards as well as the IPE. The more likely sequences that contribute to risk, the importance of equipment, systems, and human actions that determine the risk are an immediate value. In addition, cost beneficial improvements are usually identified during these studies. The following improvements or initiatives were identified during the IPEEE and resolved as summarized below:

- Racks Secured Near MOV (2ICS*MOV129)
  During the walkdown, a material storage rack near 2ICS*MOV129 was identified as having the potential to fall and impact the MOV. The rack has been secured.

- Electrical Panel Hoist Assemblies
  It was noted that several safety related electrical cabinets included a hoist assembly located on the top of the panel which could move and jar equipment during an earthquake. These hoists are used to assist personnel in moving circuit breakers during maintenance and testing. A plant deviation event report (DER 2-95-0245) was written to document this finding. The DER has been dispositioned which required the installation of a number of rail stops.

- Control Building Seismic Flood
  Prior to the seismic walkdown, the presence of fire water piping in the control building was noted and then investigated during the walkdown. There is a large fire water header in the control building corridor elevation 261 (fire area 88). Mounted on this header are deluge valves. Failure of deluge valve trim piping would cause the valve to open supplying normally dry piping. Initially there were two concerns. First, the trim piping on one of the valves is close to the wall and could be crushed if the header moves during a seismic event. Secondly, the piping down stream of the deluge valve is connected by couplings and is loosely hung close to the wall. The possibility

that the coupling could also be knocked loose or off during the seismic event existed. Initial judgment was that the fire header could be better anchored and DER 2-95-311 was written recommending additional supports. Subsequent analysis concluded that a HCLPF of 0.5g could be justified. Thus, the final decision was that modification to the piping header was not necessary.

- <u>Tornado Interaction</u>
  It was noted that construction of some new nonsafety related buildings on site did not include tornado design criteria suggested by the USAR. This situation was not found to be risk significant (see Section 5.1). However, DER 2-95-0175 was written to document the finding and suggest that the discrepancy between nonsafety related site construction design basis and the USAR be rectified.

7.3 IPEEE Insights

There were additional insights identified during the IPEEE that may be considered in the future. These insights were identified similar to those in the section above, but have not been defined in a manner that supports closure. None of the insights are particularly risk significant, but future activities may prove cost-beneficial. These insights are summarized below:

- <u>Fire Risk Insights</u>
  Potential improvements to procedures and training, in response to control room fires, were identified during the analysis. The risk from control room fires was assessed to be relatively low with existing procedures. However, these scenarios were judged to dominate fire risk at NMP2, contain the greatest uncertainty with regard to quantitative risk, and improving procedures where there are obvious limitations is not considered costly. For these reasons, potential improvements are being assessed.

  RCIC, HPCS, and emergency diesels are also important to these scenarios. Some of this importance is associated with the uncertainties in the procedures and human response from the remote shutdown panel when emergency depressurization is needed. All of these systems were also important in the IPE and considered risk significant systems in the maintenance rule. Thus, no changes in the maintenance rule implementation, regarding the identification of risk significant systems, were found.

  Automatic detection and suppression was relatively important in a few critical plant locations with regard to limiting the need for detailed fire modeling. However, actual quantitative importance is not readily available. Those plant locations where automatic detection and suppression are potentially important include the emergency switchgear rooms, control building corridor on elevation 261, and potentially some cable chase areas.

Other fire protection program requirements such as fire barriers, controls of ignition sources and combustibles, and training were not evaluated and have to be considered important without additional analyses.

- Seismic PRA Insights

Approximately 63% of core damage frequency is associated with the review level earthquake screening HCLPF of 0.5g (failure of the plant and core damage are assumed). Thus, to reduce this risk, the cost of establishing a more realistic screening criteria for component fragility has to be weighed against the benefits of having a more accurate analysis. The present risk is already low even with this limitation, thus for the present no additional analysis is planned. If a future need arises to reduce or better understand this risk, the present model can be used to support and focus that need.

Offsite power loss due to the earthquake is important, as it comprises approximately 34% of core damage frequency. However, this fragility is based on actual earthquakes and the cost of improving offsite power is judged to be significantly greater than the benefits.

Non seismic failure of RCIC and HPCS are relatively important (approximately 18% of core damage frequency) as they were in the IPE. However, the dominant scenarios are associated with seismic failure of the nitrogen system where it is assumed that in the long term SRVs close preventing low pressure injection success. Realistically, it is expected that the operators would initiate shutdown cooling. Thus, it appears the importance of RCIC and HPCS could be overstated.

Non seismic failure of the diesels contribute about 16% to core damage frequency. No credit is taken for recovering offsite power or a diesel. However, for seismic events, not recovering equipment should be relatively realistic. In addition, the mission time for the diesel was not changed from the IPE which is optimistic for seismic events. Thus, the importance of diesels is probably higher than estimated in the seismic PRA model.

Non seismic failure of RHR was next in importance (approximately 5%). This is also slightly conservative because no credit is taken for containment venting and shutdown cooling.

In summary, the importance of non seismic failures includes diesels, HPCS, RCIC, and RHR. All of these systems were important in the IPE and considered risk significant systems in the maintenance rule. Thus, no changes in the maintenance rule implementation, regarding the identification of risk significant systems, were found (note that maintaining the seismic capability of the 0.5g HCLPF success path is important). Additional analysis to remove conservatism (i.e., 0.5g HCLPF and the non modeling of shutdown cooling) is not judged cost beneficial at this time.

8.0 Summay and Conclusions

The NMP2 IPEEE set out with a number of goals and objectives. These were met by forming a capable inhouse team and performing a state-of-the-art PRA analysis of external hazards impacts on the plant.

Qunatitative results show that NMP2 poses no undue risk to the health and safety of the public. As a snapshot, the IPEEE and the IPE combined give confidence in the ability of NMP2 to safely produce electricity. Also, the study suggests that future cost effective improvements may be difficult to justify relative to external hazard risks. Clearly, the IPEEE with the IPE, as a living program, will continue to benefit the plant until decommissioning.

During the IPEEE, a number of unresolved issues were studied. Based on the IPEEE, these issues can be resolved. These issues are described in Sections 3.3 and 4.9.

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