ACCELERATED DOCUMENT DISTRIBUTION SYSTEM

REGULATORY INFORMATION DISTRIBUTION SYSTEM (RIDS)

ACCESSION NBR:9302220084 DOC.DATE: 93/02/15 NOTARIZED: NO DOCKET #
FACIL:50-263 Monticello Nuclear Generating Plant, Northern States 05000263
AUTH.NAME AUTHOR AFFILIATION
PARKER,T.M. Northern States Power Co.
RECIP.NAME RECIPIENT AFFILIATION
Document Control Branch (Document Control Desk) See Rats

SUBJECT: Responds to request for addl info concerning Monticello individual plant exam submittal per Generic Ltr 88-20.

DISTRIBUTION CODE: A011D COPIES RECEIVED:LTR 1 ENCL 1 SIZE: 93
TITLE: Generic Ltr 88-20 re Individual Plant Evaluations

NOTES:NRR/LONG,W. 05000263

	RECIPIENT ID CODE/NAME	COPIES LTTR	COPIES ENCL	RECIPIENT ID CODE/NAME	COPIES LTTR	COPIES ENCL
	PD3-1 PD	1	1	HSIA,A	1	1
INTERNAL:	ACRS HOUSTON,M	1	1	AEOD/DSP/TPAB	1	1
	NRR HERNAN,R	1	1	NRR/DREP/PRAB	1	1
	REG FILE 01	1	1	RES FLACK,J	3	3
	RES MITCHELL,J	1	1	RES/DSIR/SAIB/B	7	7
	RGN 1	1	1	RGN 2	1	1
	RGN 3	1	1	RGN 4	1	1
EXTERNAL:	NRC PDR	1	1	NSIC	1	1
NOTES:		1	1			

R I D S / A D D S

R I D S / A D D S

NOTE TO ALL "RIDS" RECIPIENTS:

PLEASE HELP US TO REDUCE WASTE! CONTACT THE DOCUMENT CONTROL DESK, ROOM P1-37 (EXT. 504-2065) TO ELIMINATE YOUR NAME FROM DISTRIBUTION LISTS FOR DOCUMENTS YOU DON'T NEED!

TOTAL NUMBER OF COPIES REQUIRED: LTTR 25 ENCL 25

mb-2

Northern States Power Company

414 Nicollet Mall
Minneapolis, Minnesota 55401
Telephone (612) 330-5500

February 15, 1993

US Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555

MONTICELLO NUCLEAR GENERATING PLANT
Docket No. 50-263 License No. DPR-22

Response to Request for Additional Information
Concerning the Monticello Individual Plant Examination
(IPE) Submittal - Generic Letter 88-20 (TAC No. M74435)

As requested by your letter of December 17, 1992, we are hereby providing our written responses to your questions concerning our February 27, 1992 Individual Plant Examination (IPE) submittal. The specific response(s) to each of your questions is contained in the attached document.

This letter contains no new NRC commitments, nor does it modify any previous commitments.

Please contact Terry Coss, Sr Licensing Engineer, at (612) 295-1449 if you require additional information.

Thomas M. Parker
Director
Nuclear Licensing

cc: Regional Administrator-III, NRC
NRR Project Manager, NRC
Resident Inspector, NRC
State of Minnesota,
Attn: Kris Sanda
J Silberg

Attachment: Responses to Written NRC Questions Concerning Monticello lPE Submittal

190084

A011
1/1

F.E. 1 NUREG-1335 states that: "The submittal should describe utility staff participation and the extent to which the utility staff was involved in all aspects of the IPE program." Although the IPE submittal states that the IPE/PRA staff consisted of 5 engineers (supported by consultants in the development of the IPE/PRA), it does not describe the extent to which your staff was involved in the performance of major tasks, i.e., systems analysis, human reliability analysis, containment performance analysis, internal flood analysis, and data collection. Discuss more explicitly your staff's involvement in the IPE process, including the independent in-house peer review, and any benefits from the review.

NSP personnel participated in all aspects of the PRA to obtain complete technology transfer. The role of consultants was to provide the initial procedure to be used to perform the various tasks and to review the results of completed tasks to assure the work was performed in a manner that was consistent with generally accepted industry practices. NSP personnel modified the initial procedures as necessary and then performed and verified the work for each task. This approach was taken for systems analysis and fault trees, event trees, data analysis, human reliability analysis, common cause analysis, internal flood analysis, source term analysis, and the quantification of the level one and level two portions of the IPE. Some of the extensive data collection work was performed with the assistance of a contract worker who gathered plant records under direct NSP supervision and entered the information in a data base. NSP personnel then verified the information in the data base and used the data base to calculate basic event values for the fault trees. For the level two analysis, NSP received generic phenomenological papers (sometimes called position papers) from a consultant and then adapted them in-house to make them plant specific. The MAAP parameter file was developed by NSP personnel. Most of the MAAP cases were run and verified in-house; those which were run by consultants were completely reviewed, verified, and interpreted by NSP personnel.

The PRA report was reviewed by the independent in-house review team as described in section 5.2 of the submittal. The individuals making up the review team included personnel from the following departments or groups:

- Design Standards section (4 people)
- Project Manager involved in control room design review and human factors
- Licensing department engineer
- Training representative
- Monticello Site Manager
- Monticello Plant Manager
- Nuclear Analysis Department Manager

Care was taken throughout the project to assure the PRA reflected the "as-built, as operated" plant. The in-house review comments demonstrated that this objective was met and no major changes were required in the report.

F.E. 2 Provide the date used for the plant configuration analyzed in the PRA/IPE.

This date is March 1, 1991.

F.E. 3 The submittal (2.4.3) identifies types of documents that were used to supply information for the analysis. However, no documents controlling plant modifications are listed. Were any modifications incorporated in the plant prior to the submittal that were not captured in the PRA/IPE? If so, discuss the impact on the results of the IPE/PRA.

The information sources used by the IPE team do capture plant modifications. The procedures, drawings, and operations manual sections are updated whenever the associated system is modified.

Of the modifications to the plant that were not included in the IPE, only one may potentially have a significant effect on the results. A fire water system cross-tie to RHR has been installed. This could enable injection of river water to the reactor or containment using a diesel-driven fire water pump. This modification may make an improvement on core damage frequency due to station blackout, if other modifications to enable reactor depressurization during a station blackout are installed also.

Four other plant modifications which affect the fault trees used for the IPE have been installed between when the IPE plant model was developed and when the submittal was made. None of these modifications is expected to materially influence the IPE results.

1. Interlocks were installed to prevent opening a shutdown cooling suction valve on RHR when its associated torus return valve is also open.

2. One of the air compressors was slightly modified to improve its reliability.

3. A valve in the service water system has been "gagged" open so that it cannot fail to remain open.

4. The inboard RCIC and HPCI steam line isolation valves no longer receive an open signal on system initiation. These valves are normally open.

F.E. 4 Section 2.4.4 of the submittal discusses "Walkdowns," but does not explicitly identify System walkdowns done to assure that the systems modeled actually represent the systems. Discuss the process used to confirm that the PRA/IPE represents the "As-Built, as Operated" plant, including a discussion of the documentation used and system walkdowns.

Group walkdowns performed by IPE team members were formally performed and documented and are briefly described in section 2.4.4 of the submittal. In most cases, the individual walkdowns performed for systems analysis and fault tree construction were part of an iterative process and not continuously documented. They were performed as often as necessary to answer questions that arose during fault tree construction. Individual walkdowns were performed by this method because the majority of the front end work was performed by the NSP analysts stationed at the Monticello plant.

The Monticello PRA model is an accurate reflection of the "As-Built, As Operated" plant. NSP has PRA personnel permanently located at the Monticello site and maintains additional office space at the site to facilitate temporary visits as required by the other IPE team members. SRO trained individuals either developed or reviewed every fault tree. One of the individuals assigned to the PRA team was also in the walkdown stage of SRO training and used the system notebooks and fault trees as an additional guide in his self study preparation for many of the SRO certification walkthroughs. The plant system engineers reviewed the system notebooks for their systems including fault tree assumptions and interpretation of the results. The comments received from the system engineers and their resolutions are documented in the final revision of the system notebooks. The Monticello Operations Manual contains much of the information needed for PRA systems analysis and is kept up to date by the plant staff. All updates to the operations manual, technical specifications and design changes which occurred after the start of the PRA work were reviewed to determine if they would impact the PRA.

F.E. 5 Section 2.3.1 indicates that many of the same functions and systems in the Level 1 Analysis appear in the CETs. Provide a discussion describing how failures in systems in the Level 1 Analysis are accommodated in the CETs.

The fault tree linking process was used to ensure component failures which occurred in the Level 1 Analysis were accounted for in the Level 2 Sequence Analysis. The minimal cutset equations generated for the Level 1 Sequences were used as input to the Level 2 CET Analysis. These minimal cutset equations carried with them the component failures and failure modes that occurred in the Level 1 Analysis.

F.E. 6 Section 3.1.1.1 does not a.) address NSP's determination of the completeness of the set of initiating events chosen for the Monticello IPE nor b) does it explain the process used to identify unique system specific initiators. Please provide a description of the process used to determine a & b above and identify any references used including other PRAs and NUREG documents.

NSP used the initiating events identified in the Reactor Safety Study (WASH-1400) and the IDCOR BWR Individual Plant Evaluation Methodology as a starting point for selecting the initiating events that could occur at Monticello. In addition, reactor trip reports and control room log books were reviewed for 18 years of plant operation to account for plant specific history of initiating events. Dependency matrices were developed to examine the effects of support systems on important front line system operation. No new initiating events were identified that have not been included as a part of previous PRAs.

F.E. 7 Section 3.1.1.3 indicates that loss of any (non-specific) 125 V DC BUS is an event but loss of an A.C. Bus is not. Loss of the 120 V AC vital power supply is not addressed. Provide a discussion of your examination of the onsite A.C. (4160V, 480V 120V) and D.C. (125V & 250V) systems for unique system initiators. Address the ability of your examination to identify asymmetries between buses, the impact on plant system and plant trip, and the basis for inclusion or elimination of AC/DC buses as an initiating event.

All AC and DC power supplies that support equipment credited in the IPE are explicitly included in the models by linking the support system fault trees to the frontline system fault trees. Any vulnerability to a loss of a single bus would be identified this way. Also, since each bus has its own fault tree, any asymmetries would be identified by this approach.

Loss of an AC bus was not included as an initiating event, as the effect of a loss of a single AC bus would be encompassed by the initiating event for loss of offsite power.

F.E. 8 NSP's assessment of LOCAs and steam line breaks which impact mitigating systems and components (including MOVs and instrumentation) and the impact on the IPE results is not addressed. Provide a discussion of your assessment of equipment survivability under harsh environments such as LOCAs and steam line breaks.

It was assumed throughout the IPE that if the environmental qualification limits were exceeded for a component, the component would fail. Below the environmental qualification limits, random component failure rates were assumed.

For LOCAs and steam line breaks, the equipment which would be exposed to harsh conditions in the drywell either operates at once or is not required to operate. The MSIVs and other containment isolation valves close immediately, before the harsh conditions can degrade their performance. The HPCI and RCIC steam supply valves are normally open. For a steam line break or a large or medium LOCA, the safety relief valves are not required to operate, since the vessel will depressurize through the break; these valves may be needed during a small LOCA, but the environment during a small LOCA is not harsh enough to disable the SRVs. Other equipment, such as the required instrumentation, ECCS pumps, and ECCS water supply valves, is located outside containment.

F.E. 9 Section 3.1 identifies interfacing systems LOCA as a type considered in the analysis. However, there is no description of how the frequency of this event was estimated. Provide a discussion (with simplified diagrams) of the specific systems and components considered and their associated failure modes as modeled for the ISLOCA initiator.

Here is a table that shows the various ISLOCA systems considered, references to simple figures in the IPE submittal, and a description of the ISLOCA sources considered for each system.

SYSTEM	DRAWING	ISLOCA SOURCES CONSIDERED
Main Steam	Figure 3.2-21	(1) Pipe rupture between containment and outboard valve with inboard valve failure to close. (2) Rupture of outboard valve with inboard valve failure to close. (3) Rupture downstream of outboard valve with any main steam line failure to isolate.
Feedwater	Figure 3.2-10	(1) Pipe rupture between containment and outboard check valve (FW-94-1/2) with inboard check valve failure to close or severe leakage. (2) Rupture of outboard check valve with inboard valve failure to close or severe leakage. (3) Rupture between outboard check valve (FW-94-1/2) and third check valve (FW-91-1/2) with common cause inboard and outboard check valves failure to close or severe leakage.
Core Spray, LPCI & Head Spray	Figures 3.2-17 & 3.2-18	(1) Interlock failure, allowing both MOVs to be open at once, AND operator fails to follow the test procedure, AND inboard testable check valve failure to remain closed/severe leakage, AND low pressure piping conditional rupture. (2) Failure of air testable check valve to remain closed AND failure of MOV to remain closed AND low pressure piping conditional failure.

SYSTEM	DRAWING	ISLOCA SOURCES CONSIDERED
Shutdown Cooling Suction	Figure 3.2-23	Common cause failure of isolation valves to remain closed AND low pressure piping conditional rupture. (Note: Monticello follows the practice of maintaining these valves closed with one of the associated circuit breakers open during reactor operation.)
HPCI & RCIC Steam	Figures 3.2-13 & 3.2-14	(1) Pipe rupture between containment and outboard valve with inboard valve failure to close. (2) Outboard valve rupture and inboard valve failure to close. (3) Rupture between outboard valve and steam admission valve with common cause failure of both inboard and outboard isolation valves to close.

F.E. 10 Since the conditional pipe rupture probability (0.01) was considered an important/sensitive assumption (3.4.2.8), what is NSP's assessment of the impact of this assumption on the IPE results?

This assumption affects ISLOCA sequences. If the assumption were changed such that the conditional pipe rupture probability was 1, then the frequency of core damage due to ISLOCA could increase to about 1E-8/year. This is still less than one percent of the total core damage frequency calculated in the IPE.

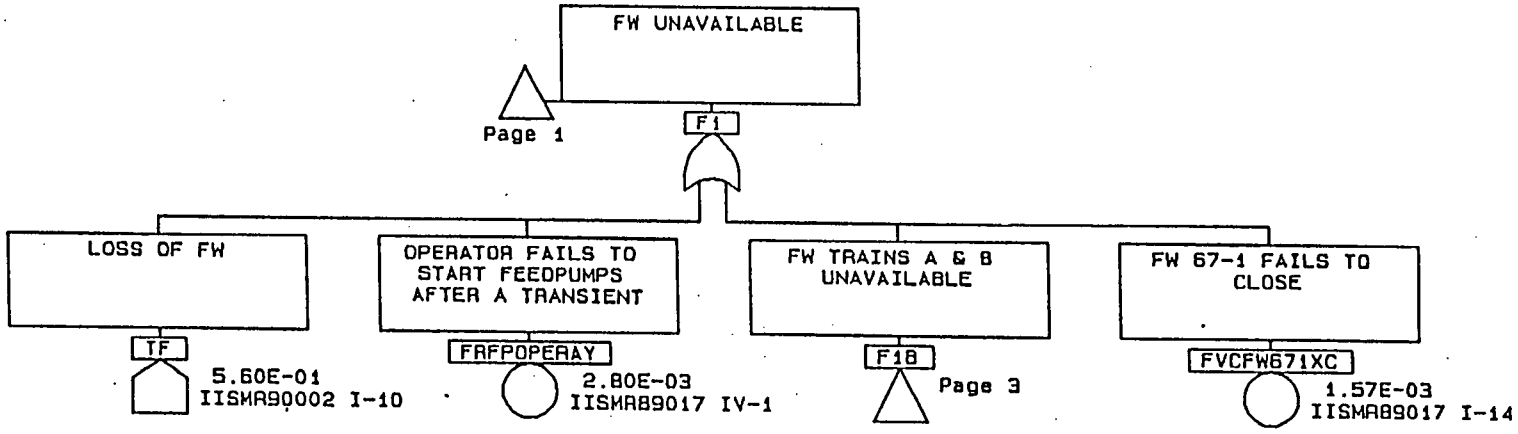
F.E. 11 Section 3.1.2.3 (assumptions) #14, asserts that some sequences were not explicitly quantified because when combined with the RPS initiation event their probability was less than 5E-7. This does not appear to be the case for Loss of Instrument Air (6E-2 x 3E-5 = 1.8E-6). Please address this apparent discrepancy & discuss its impact on the PRA/IPE results.

You are correct that, by our stated guidelines, loss of instrument air should have been included in the ATWS quantification. However, loss of instrument air has the same impact on plant and system response to ATWS as loss of the main condenser. Scaling the results of loss of the main condenser ATWS sequences, results in a minor increase of 4.7E-8/yr in core damage frequency.

F.E. 12 Since the Monticello IPE does not provide a separate event tree to distinguish between events with PCS available; PCS unavailable and LODC Bus, describe how events (such as LOFW, LO condenser Vacuum, loss of service water etc.) that have significantly differing effects are accommodated in the single event tree for anticipated and special initiators. Please provide sample fault trees for your example and supporting documentation for understanding nomenclature and the process used, as appropriate.

Initiating events were included in the fault trees of the systems that they would affect. For instance, the loss of feedwater initiating event is included on the fault tree for the feedwater system, in such a way that "loss of feedwater" causes the system to be unavailable. Therefore sequence quantification with a loss of feedwater initiating event would automatically capture the fact that the feedwater system would not function. The same method was used for the main condenser, service water, instrument air, and other fault trees.

The next page shows a portion of the feedwater fault tree which includes initiating event TF, "Loss of FW."



FEEDWATER/CONDENSATE SYSTEM FAULT TREE	F.CAF	7/20/91	Page 2

F.E. 13 Table 3.1-2 "Frontline success criteria" indicates that one RHR pump is required for Containment Heat Removal for all accident initiators listed. However section 3.2.1.1.4 indicates that one is required for "most" initiating events. Section 3.1.3 (success criteria) does not discuss which events require more than one. Provide a description of your assessment of which events require more than one RHR pump, discuss how this is included in the PRA/IPE and what the impact is on the results. In addition, address the requirements under containment heat removal for the RHRSW System.

The word "most" in section 3.2.1.14 is inappropriate; a single RHR pump was sufficient for all initiators.

Regarding the RHRSW system, in Table 3.1-2 under the heading "Containment Heat Removal," wherever "1 RHR Pump" is given as a success criterion, it should say, "1 RHR Pump and 1 RHRSW Pump."

F.E. 14 Table 3.1-2 and Section 3.1.3 do not address the success criteria for loss of offsite power. Provide a discussion of the frontline system success criteria for this event.

The loss of offsite power success criteria would be the same as for the other transients listed in Table 3.1-2, with the exception of feedwater, condensate, and the main condenser, which would be lost with offsite power. This would leave LPCI, Core Spray, ADS, RHR Pump, and the containment vent for the frontline system success criteria in the respective columns of Table 3.1-2.

F.E. 15 Table 3.1-2 and Section 3.1.3 do not address success criteria for maintaining the reactor subcritical. Please address this criteria for the events considered in your PRA/IPE and provide a discussion of how recirculation pump trip is considered in conjunction with ARI, SLC and Manual rod insertion in the fault trees for top event "C" in the event trees.

Table 3.1-2 did not address the criteria for maintaining the reactor subcritical. This was discussed in Table 3.1-3, and Section 3.1.1.3-ATWS. A specific event tree was used to investigate the ATWS sequences (Figure 3.1-12). The success criteria, from table 3.1-3, require one recirculation pump to trip and one standby liquid pump to inject. Also CE and CM, electrical or mechanical RPS failure, assumed failure such that manual rod insertion was ineffective, therefore no manual rod insertion was considered.

F.E. 16 Please provide a brief description of the question, equipment & human actions which make up top events DG1, DG2, DG3 and UH.

DG1 represents the failure of both emergency diesel generators. It is composed of a minimal cutset equation of combinations of failures that would cause both diesels to fail.

DG2 is a diesel generator non-recovery factor within two hours after failure. This was calculated based on a table in the IDCOR BWR Individual Plant Evaluation Methodology which got its data from NUREG/CR-1362.

DG3 is the conditional non-recovery factor for a diesel generator at four hours given that neither diesel generator was recovered at two hours. This was calculated the same way as DG2.

UH is an operator error to control reactor water level after injection of sodium pentaborate. Failure of UH leads to a boron dilution and recriticality.

F.E. 17 Transfer to Phase IV appears in the LOOPIII.TRE. Please explain which tree is Phase IV; it doesn't appear in the figures.

The event trees for loss of offsite power were developed to be flexible so that they could be used if the plant was modified to improve the capabilities of reactor depressurization and coolant makeup during a station blackout. Currently, the analysis assumes that failure always occurs for functions QU (high pressure coolant makeup), X (reactor depressurization), and V (low pressure coolant makeup) during phase III of a station blackout. Therefore, the branches of the event tree that indicate a transfer to phase IV are not used and an event tree for phase IV was never developed.

F.E. 18 A number of submittals have indicated that loss of HVAC to various areas (including the control room) in the plant impact front line and support (including AC and DC) systems and contribute to core damage and release frequency. Please provide a description of your investigation into the impact of loss of HVAC to the rooms containing AC & DC power equipment and the control room on core damage. Discuss the systems and areas considered, the method used to perform the assessment (including calculations and/or Test), credit given for operator action, rationale for inclusion or elimination of a particular area or system (as a support system) and the impact on the results of the IPE/PRA. In addition discuss loss of HVAC to these and other areas as possible initiating events.

The assumption that loss of HVAC will not result in the loss of AC, DC or control room components was based on engineering judgement. The three systems are discussed further below, followed by a discussion of possible initiating events.

AC distribution

The assumption that room cooling was not necessary for the 4KV rooms was due to engineering judgement based on the rooms' configurations within the turbine building. The upper halves of the rooms are enclosed by deck grating for walls and are open to the surrounding area such that large portions of the turbine building must heat up in addition to these rooms. Even if the rooms would heat up, procedures are in place that direct operators to open doors and use dedicated portable fans (stored next to the 4KV rooms) if ventilation is lost to the rooms. Operators check the room temperatures about every four hours. Special plant testing was performed to confirm that those compensatory measures would be effective in controlling temperature.

DC distribution

Excluding the battery room exhaust fans from the IPE model was based on the assumption that the fans are used to prevent hydrogen produced during charging from collecting in the battery rooms, and that because significant charging is not performed during normal operation, hydrogen buildup within the rooms will be minimal.

The exhaust fans for the battery rooms were installed in a reliable configuration. There is one set of exhaust fans for the three battery rooms in the main access control area. The set consists of two fans in parallel, one receiving power from essential MCC 133A and the other from essential MCC 143B. The Division II 250 V battery room has its own set of exhaust fans. The set consists of two fans in parallel, one receiving power from essential MCC 134 and the other from essential MCC 144.

If ventilation is lost to a battery room it is not expected to heat up due to lack of significant heat sources. Even if ventilation is necessary, procedures are in place that direct operators to open doors and use dedicated portable fans if ventilation is lost to the battery rooms in the main access control area (Div I 125 VDC, Div II 125 VDC, and Div I 250 VDC). An alarm alerts the operators to loss of air flow to the rooms. Thermometers are installed in each battery room to alert the operator of increasing temperatures. The rooms are checked about once a shift.

Control room HVAC

Control room cooling was assumed to have negligible impact on core damage frequency because the control room is continuously manned. If HVAC failed the operators would get uncomfortable and set up temporary means to cool the area such as opening doors and setting up fans. If the temperature continued to increase and the operators had equipment operability concerns they could send personnel to the alternate shutdown panel.

Control room HVAC is installed in a reliable configuration and requires more than one support system failure for the system to fail. To fail both trains of control room HVAC, either service water and both trains of emergency service water must fail, or both divisions of essential power must be lost. It would be unlikely for both the control room and alternate shutdown panel area to lose room cooling because there are few common support systems. The alternate shutdown area HVAC is a self contained unit that only requires electrical power. Therefore, control room and alternate shutdown panel area cooling cannot both be lost unless there are multiple failures in the electrical distribution system.

Initiating events

NSP believes that loss of HVAC to the three areas mentioned above would not be an initiating event. If in fact the rooms actually were to heat up substantially, a manual shutdown may be initiated. Because the HVAC in these areas is reliable, this contribution to manual shutdown frequency would be much less than the total frequency of manual shutdown and therefore would have little impact on the PRA results.

The impact of the loss of HVAC is discussed in section 3.2.1.26 of the PRA submittal. MSIV closure due to loss of cooling to the steam tunnel is briefly discussed there. The frequency of the MSIV closure initiating event was calculated from plant data. Once again, the historical plant-specific frequency of the MSIV closure initiating event is expected to exceed that resulting from loss of steam tunnel HVAC.

F.E. 19 As part of your IPE what support systems has NSP determined to be significant contributors to core damage (please list by percentage contribution to core damage) and what insights to the possible reduction in core damage from these systems have you gained?

The support systems listed on Table 3.2-5 of the IPE were examined to determine their Fussel/Vesely rankings. Support systems are listed below, along with their percentages. Support systems which do not appear in this list, such as RBCCW, were sufficiently low in importance that they were truncated from the results.

AC	58.0%
Emergency Service Water and Emergency Diesel Generator Service Water (most of this is EDG-ESW)	19.0%
DC	.5%
RHR Service Water	.4%
Service Water	.25%
Instrument Air	.2%

This reinforced our knowledge of the importance of the AC and EDG-ESW systems in their contributions to loss of offsite power events, which make up 70% of the internally initiated core damage frequency at Monticello.

F.E. 20 The table of sequences (1.4-2) appears to list the sequences in an abbreviated form (e.g., SBO-LONG,) which do not contain the disposition of all the top events, in the sequences. Please provide the full sequences.

The sequence for SBO-LONG is TE, I, DG1, II, DG2, III, DG3, QU, X.

The sequence for SBO-QU is TE, I, DG1, QU, X.

The sequence for SBO-P is TE, I, DG1, P, V.

Where:

TE	= loss of offsite power.
I	= non-recovery factor for offsite power at 30 minutes.
II	= conditional non-recovery factor for offsite power in 2 hours, given that it was not recovered at 30 minutes.
III	= conditional non-recovery for offsite power in 4 hours, given that it was not recovered in 2 hours.
DG1	= failure of both diesel generators.
DG2	= non-recovery factor for a diesel generator in 2 hours.
DG3	= conditional non-recovery factor for a diesel generator, given that neither diesel generator was recovered at 2 hours.
QU	= failure of high pressure coolant make up.
X	= failure to depressurize the reactor.
V	= failure of low pressure coolant make up.
P	= failure of SRV to close.

F.E. 21 Failures of HPCI and RCIC are stated (pg. 3.4-7) to be important contributors to the class 1A damage class (transients). Please describe your investigation into these major contributors and discuss any insights gained regarding contributions (including percentages) from failure modes, failure frequency, scheduled maintenance repair time, testing and human actions.

RCIC appeared in 73% of the cutsets of class 1A (F/V=73) and HPCI appeared in 69% of the cutsets (F/V=69). HPCI was largely dependent on failure to start or run of the HPCI pump or auxiliary oil pump (61%). The testing of HPCI amounted to 8% of its unavailability. Maintenance and valve failure amounted to about 1% each. No human actions were credited during the accident or post accident due to the limited time available. This was true for both HPCI and RCIC. RCIC was largely dependent on failure of the RCIC pump to start or run (36%). Testing and maintenance amounted to 1% each. RCIC valve failure amounted to 23% of the system unavailability.

F.E. 22 The staff notes that your method (identified on page 3.3-3) chosen to determine the failure rates for components that have experienced zero failures is not a standard statistical technique. In order for the staff to achieve a better understanding of your application and use of this method in meeting the IPE objectives, concisely describe the rationale behind the application of your methods, specifically with respect to your institution and use of 0.5 failures in some situations (where zero failures have occurred), and application of generic data in others. Per NUREG-1335, identify those instances where the 0.5 estimate, or the generic estimate, was applied for system or component having zero failures. Note any sensitivity studies performed, or insights gleaned from other probabilistic studies to support your justification as appropriate.

The method used to calculate the failure rates for components which have experienced zero failures is a reasonable way to estimate failure rates of plant components where a number of demands or run-hours have occurred, but no failures have been experienced. If this estimate produces a higher failure rate than published generic data, then it is assumed that the reason is because there have been too few run-hours or demands. In this case the use of a generic failure rate would be more accurate.

Note that the half-failure approximation is about equal to the equation produced by the Baysian update of a non-informative prior:

$$\text{Mean} = (2n+1) / (2T) \qquad \text{time-related failure}$$

$$\text{Mean} = (2n+1) / (2D+2) \qquad \text{demand-related failure}$$

where:

n = number of failures,
T = time period, hr, and
D = number of demands.

Setting $n = 0$ for these equations produces:

$$\text{Mean} = 0.5 / T \qquad \text{time-related failure}$$

$$\text{Mean} = 0.5 / (D+1) \qquad \text{demand-related failure}$$

As requested, below is a listing of the component failure rates which used the half-failure approximation and the rates for which the half-failure approximation was rejected and generic data used.

Half-failure approximation used

Battery failure to operate
Mechanical switch interlock failure
Emergency diesel generator failure to run
Inverter Y-81 failure to operate
4160V to 480V transformer failure to operate
Safety/relief valve failure to open
RHR service water pump failure to run

Half-failure approximation rejected, generic data used

Standby liquid control pump failure to run
Emergency diesel generator cooling water pump failure to run
Liquid nitrogen tank rupture / severe leak
Motor-operated valve failure to remain open
Motor-operated valve failure to remain closed
Main steam isolation valve failure to remain open
Air-operated valve failure to remain open
Air-operated valve failure to remain closed
RHR heat exchanger river water discharge control valve failure to remain open
Service water pump failure to run
Instrument air compressor failure to start
Reactor building closed cooling water pump failure to start
Reactor building closed cooling water pump failure to run
Mechanical vacuum pump failure to start
Circulating water pump discharge bellows rupture / severe leak
RCIC governing valve failure to operate
Main steam isolation valve failure to open
Main steam isolation valve failure to close
Bus tie circuit breaker failure to remain open
Emergency diesel generator output breaker failure to open

F.E. 23 Sections 3.3.4.2 and 3.3.4.3 indicate that maintenance and testing activities are of importance, but no explanation of how these activities were incorporated in the fault trees was provided. Per NUREG-1335 reporting guidelines, describe the method used to calculate unavailability and discuss the impact this has on its contribution to system failure. Discuss the insights into the significance of the contribution to core damage from maintenance/testing activities that NSP has gained from incorporating these activities in the model.

Testing, corrective maintenance, preventive maintenance, and restoration error unavailabilities were included on the fault trees for the plant systems. An example is shown on the next page.

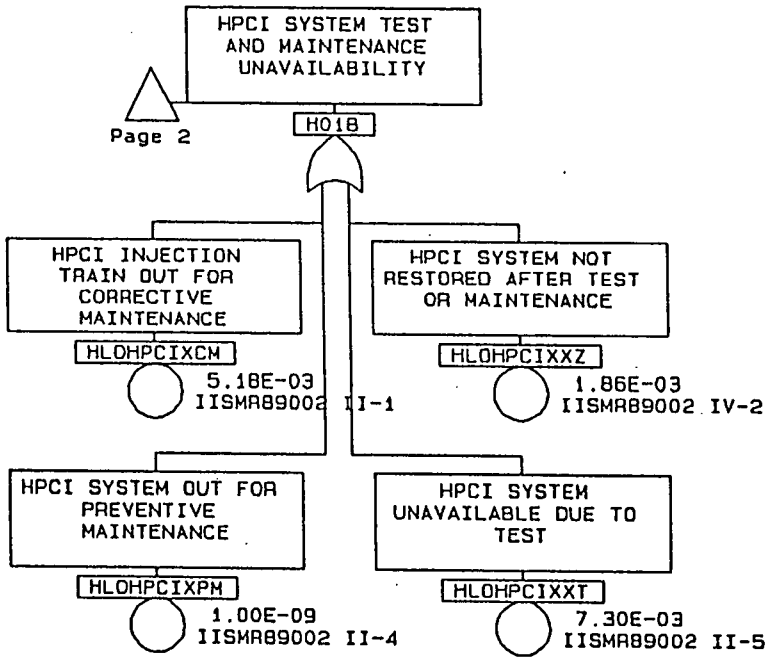
Corrective maintenance unavailability was calculated by reviewing several years of work order records for the systems covered by the IPE. The duration out of service for the work orders was totaled and divided by the total hours of reactor operation during the same period. Maintenance which did not affect a system's ability to perform its function, or which occurred during a reactor outage was not counted in this calculation.

Preventive maintenance and testing unavailabilities were calculated by reviewing the procedures that direct these activities. An estimate was made of how long each procedure would make the affected system unavailable. Computer records were then used to determine the number of times each procedure had been performed during reactor operation. The unavailability is simply the number of hours unavailable per procedure times the number of times the procedure was performed divided by the reactor critical hours during the same period.

The Fussel Vesely ranks of individual basic events showed the following percentages of core damage frequency attributable to testing and maintenance.

Corrective Maintenance	2.6%
Preventive Maintenance	0.0%
Testing	3.8%

This study reflects Monticello's practice of not performing preventive maintenance on important components with the reactor critical.


HPCI SYSTEM TEST AND MAINTENANCE UNAVAILABILITY
H018
Page 2
HPCI INJECTION TRAIN OUT FOR CORRECTIVE MAINTENANCE
HLOHPCIXCM
5.18E-03
IISMR89002 II-1
HPCI SYSTEM NOT RESTORED AFTER TEST OR MAINTENANCE
HLOHPCIXXZ
1.86E-03
IISMR89002 IV-2
HPCI SYSTEM OUT FOR PREVENTIVE MAINTENANCE
HLOHPCIXPM
1.00E-09
IISMR89002 II-4
HPCI SYSTEM UNAVAILABLE DUE TO TEST
HLOHPCIXXT
7.30E-03
IISMR89002 II-5

F.E. 24 In section 3.3.4.1 restoration errors were identified as possibly causing system unavailability. Describe the method used to incorporate restoration errors in the system models. Provide examples for components/systems where they were incorporated in the model and address their contribution to system unavailability.

See the figure in the response to question F.E. 23 for an example of how restoration error unavailabilities were included on system fault trees.

Restoration error unavailability was calculated by counting one restoration following every test or maintenance activity that rendered the system unavailable, plus an additional restoration at the conclusion of every refueling outage. This was multiplied by an estimate of the error rate per restoration. The expected duration of the error was also factored in, crediting post-maintenance and surveillance testing for discovering errors where appropriate.

Restoration errors did not account for much system unavailability or core damage frequency. Totalling the Fussel Vesely values for all restoration errors showed that only 1.6% of core damage frequency is attributable to restoration errors.

F.E. 25 In section 6.4, it is stated that "Maintenance provided only a limited contribution to system unavailability due to the Historical Practice of not performing on-line preventive maintenance." As an example, discuss the limited contribution due to maintenance on the diesel generators. Please address the percentage contribution to unavailability, and provide the information used in incorporating this unavailability in the system fault tree model including type and frequency of maintenance as identified from plant data.

The frequency of emergency diesel generator (DG) corrective maintenance unavailability was 1.10E-4/hr per DG with an average duration of 9.62 hours. This led to an unavailability of 1.05E-3 per DG. This value was put in at the fault tree level for DG out for maintenance. The value for Preventive Maintenance used at the same fault tree level was "zero". The Fussel/Vesely or percentage contribution to the system unavailability is 3.32E-2 (3.3%) for 12 DG and 4.01E-2 (4.0%) for 11 DG. The random failure probabilities for the diesels are:

- Fails to run 8.3E-3
- Fails to start 3.7E-3
- Out for corrective maintenance 1.1E-3

F.E. 26 Describe your investigation of plant data to determine common cause events that could be of significance to your IPE. Discuss the insights gained.

The published data used in the common cause failure analysis was given in section 3.3.5 of the submittal as EPRI NP-3967, NUREG/CR-2770, NUREG/CR-2098, EGG-EA-5623, NUREG/CR-2099 and NPRDS data. In addition to the published sources, the plant data obtained as described in section 3.3.3 of the submittal was checked for common cause events. There was only one instance found where a common cause event existed in the plant data but not in the published data used for the common cause group. The event involved improper fuse coordination for the Standby Liquid Control system at Monticello (LER 86-16). For this one case the plant event was added to the published events and then the calculation for this group was performed.

No significant insights were gained from the plant-specific common cause analysis that the PRA analysts were not already generally aware of from reliability studies performed at Monticello and other plants. There were eight common cause events that had more than a 1.0% contribution to core damage frequency, i.e., had a Fussel/Vesely value greater than 1.0%. Five of the eight events were related to common cause failure of EDGs or EDG support systems (ranged from 23% to 1.1%). The others were common cause failure of ATWS RPT circuit breakers (2.6%), common cause failure of 2 vacuum breakers to close (1.2%) and common cause start failure of both HPCI and RCIC pumps (1.1%).

F.E. 27 Section 3.3.5 indicates that common cause event probabilities were estimated "in the framework of the Multiple Greek Letter Model." Please provide an example of how the factors in Table 3.3-7 were obtained for "MOV FTO/C" (2,3, & 4 components) and "RHR Pumps FTS FTR." Provide all supporting documentation necessary for understanding the nomenclature, data and process used.

The Multiple Greek Letter (MGL) approach to common cause failure analysis is presented in some detail in NUREG/CR-4780 and is the basis for the common cause analysis performed for the Monticello PRA. A copy of the calculation performed for MOVs is enclosed as attachment 1 to this letter. A copy of the calculation performed for the RHR pumps is enclosed as attachment 2 to this letter. The values do not always exactly agree with the values in table 3.3-7 of the submittal. The values given in the submittal were calculated in 1989 and are the values used in the Monticello PRA. An update to the calculations was performed in 1991 and the results were compared to the values used in the analysis. There were no significant changes between the values used in the PRA analysis and the new recalculated values. The calculations included with this letter are the 1991 calculations.

F.E. 28 The application of internal flood methodology, with respect to identification and selection of flood sources, frequency estimates, mitigation actions, flood propagation to redundant safety related equipment, qualification of equipment exposed to spray, etc., can have a significant impact on the perception of flood as a contributor to the core damage frequency. In order for the staff to fully understand and appreciate your treatment of internal flood, concisely describe the integration of this initiator into your PRA, i.e., discuss the structure of the internal flood event tree employed and integration of the impact of flood into the fault tree analysis. In addition, concisely discuss the rationale supporting the treatment, or assumptions (as appropriate), of the following aspects of the internal flood analysis reported in the Monticello IPE submittal, including the perception of these aspects with respect to their overall significance to core damage/early containment failure:

- Estimation of the flood frequency (e.g., length of pipe, etc.), and the relationship of this frequency to the assumed 50% chance of one flood occurring over the lifetime of the plant. (Also define lifetime of plant [years]).
- the term "bounded" in the section on turbine building operating floor (pg 3.4-6.5).
- inter-zone flood propagation due to back flooding through drains, open flood doors, penetration seals, etc.
- spray or direct impingement of water on plant equipment.
- treatment of circulating water system expansion joints, and potential for circulating water pump trip, back flow through the break, and isolation capability.

As per NUREG-1335, Section 2.3, also describe any strategies or potential improvements, and disposition of potential improvements, that stemmed from your treatment of internal flood in your IPE.

The response for this question has been divided into six categories and each is discussed separately below.

Modification of event trees and fault trees

On completion of the initiating events analysis and the FMEA (as described in section 3.3.8 of the submittal) sequence quantification was performed using the internal events event trees and critical safety function equations as a basis. These are the same equations for functional headings that are described in section 3.3.7 of the IPE submittal. Failures postulated to occur as a result of the flood were related to components represented by

basic events within the critical safety function equations for that initiator. In this manner the failure rate of the appropriate basic events were set to OMEGA (one) when the sequences were quantified for the particular flood initiator.

Sequence quantification for the Monticello internal events PRA has been completed using fault tree linking with a truncation probability seven to ten orders of magnitude less than typical internal events initiator frequencies. This level of detail, the relatively low frequency of flooding initiators, and the ability to reflect the effects of the flood through basic events already existing in the equations representing the functional headings permitted completion of flooding sequence quantification without the need to construct or revise logic models explicitly for the purpose of performing a flooding PRA.

Attention was focused on the short term event sequences, such as transients with failure of all injection systems (TQUX and TQUV). ATWS events were not considered in the flooding analysis because of the low failure rate of the RPS system and the observation that the standby liquid control system was available for any flooding sequence. PCSETS was used to perform the quantification of the core damage sequences.

Flood frequency

The objective of the flood analysis was to determine if Monticello had any vulnerabilities to internal floods and to find insights while performing the analysis. The estimation of flood frequency due to passive failures was based on plant specific information obtained from walkdowns and generic failure rates for components. The information obtained from the walkdown was examined to find the potential flood sources that would dominate each flood zone's impact on the PRA. The potential flood sources for each flood zone were determined and grouped as pipe greater than 3 inches, pipe less than 3 inches, valves, or tanks. Generic component rupture frequencies were then applied to the totals of each group. Then the rupture frequency obtained for each group of a particular flood zone was summed to obtain the passive failure flood frequency estimate for the flood zone.

A review of Monticello's operating experience was performed. No significant flooding events were found since the plant began operation. This information was used to calculate a conservative value for the plant's total flood initiating event frequency assuming a value of 20 years for the operating life at the time of the study. Because no event occurred in 20 years, a calculated value for flooding events due to all causes should come out to less than 1 event every 20 years. We chose to estimate the value by assuming .5 events every 20 years. (See the response to question F.E. 29). In the submittal this was called an upper bound. In reality it mathematically is not an upper bound, but it is believed to be a conservative estimate.

The above method gave an estimated value of .025 flood events per year at Monticello due to all causes, including passive failures and maintenance events. This value was consistent (larger) with the value calculated for floods due to only passive failures which was calculated to be .008. The difference, .017 events per year, was then assumed to be due to flood events caused by human error during maintenance and testing.

Certain areas were determined to have an extremely low likelihood of a maintenance flooding event because of the lack of components for which maintenance would be performed. Those areas were flood zones 1, 11 and 12, and the initiating event frequency for the three zones was therefore assumed to be due to passive failures only. The .017 events per year was then distributed among the other flood zones in proportion to the passive failure (pipe break) frequency.

The total flood initiating event frequency due to all causes for all the flood zones summed gives Monticello's internal event flood initiating event frequency and is .025 events per year.

Fire line break on operating floor

The turbine operating floor is a large open area and has a much larger floodable area than the other floors of the turbine building. No safety equipment located in the room will be affected by flooding, but equipment on lower floors could be affected.

There are various flowpaths to the lower elevations including drains, hatches to the condenser room and three stairwells. It was concluded that all feedwater line breaks above the turbine operating floor would drain to the condenser room. The effect of feedwater line breaks were the same as analyzed in the condenser room portion of the flood analysis. The only other potentially significant flood water source on the turbine operating floor was fire protection system pipe. Water from a fire system pipe break was assumed to drain via the stairwells to one of three areas. The three areas correspond to flood zone 9, flood zone 11 and flood zone 12 which are described in section 3.4.5.3 of the submittal. In these three areas there are pipes that are larger than the fire lines above the turbine floor. The effects of these larger pipe breaks are greater than fire protection system pipe breaks on the turbine floor. This is what was meant by the term "bounded." Floods from these larger breaks were covered in flood zones 9, 11 and 12.

Inter-zone flood propagation

Flooding in the reactor building cascades down all floors to the lowest level of the reactor building. Backflow was examined for the drains of the lowest floor of the reactor building. HPCI and RCIC rooms were not examined because the two systems were assumed to be disabled by reactor building floods. The torus room was assumed to flood for all reactor building floods. The other two corner rooms (RHR rooms) were examined and it was determined that back flooding through drains would not disable the equipment in the rooms (RHR and Core Spray). There are two sump pumps in each RHR room. Worst case backflow to an RHR room through the orificed drain line was found to be less than the capacity of one of the room's sump pumps. Because there are two sump pumps in each room, the sump pumps are powered by different essential MCCs in the turbine building, and the turbine building MCCs are not affected by the flood, backflow to the RHR rooms was not considered any further. A cursory look at backflow was performed for the turbine building, but due to limited flow rate combined with factors such as large floor area or sumps, it was not considered any further.

There are no flood doors in the turbine or reactor building at Monticello. Doors which open away from the flood are assumed to fail before the water rises two feet above the floor (based on a simple calculation), allowing water to flow into and affect equipment in adjacent areas. Doors which open into the region of the flood are assumed to remain closed. Leakage under the door into adjacent areas and consideration of its effects were estimated. Normally closed fire doors left or propped open against plant policy were not factored into the analysis because they are not expected to be open and if they were, the amount of time they would be open is small and their being open must occur simultaneously with the flood to have an effect on the analysis.

Open penetrations between areas identified during plant walkdowns were taken into account when dividing the plant into flood zones. Normally sealed penetrations such as cable penetrations between buildings were considered to be adequate barriers in the analysis and, furthermore, they generally are located at higher room elevations than most flood events would be expected to reach.

Water spray on equipment

Piping located over important equipment that could only affect that specific piece of equipment or system was not considered to have a significant effect. A break of that piping, usually low capacity or normally idle systems, was considered a passive failure. The passive failure of the system from a pipe break was assumed to not contribute significantly to the overall system failure rate. Failure of more than one system by low pressure, low capacity systems by spray was not considered because there is generally a reasonable distance between different systems to prevent this from happening. Spray from high capacity pipe in a flood zone was included because breaks large enough to flood a room were conservatively assumed to fail all equipment in the flood zone.

Circulating water expansion joints

The intake structure is arranged at Monticello such that the circulating water pumps are located at a lower elevation than all other pumps in the room. The floor of the circulating water pump pit is 20 feet below the main floor of the intake structure. There are expansion bellows associated with the circulating water system which are located in the circulating pump pit in the intake structure and the condenser pit in the condenser room of the turbine building. Water level sensing probes have been installed in the circulating water pump pit and the condenser pit.

If water level reaches about one foot in the circulating pump pit an annunciator alarms. If water level continues to rise and two out of three level switches trip, additional annunciators will alarm and the circulating pumps automatically stop. Even if the pumps did not automatically trip, when the water level in the pit rises to the point that the pump motor and exciter is flooded, the pumps will stop. If a break occurs in the piping in the circulating water pump pit that can not be isolated, an equilibrium water level due to gravity assisted backflow to the pit will be reached inside the pit and is not expected to overflow the pit. If the circulating water pump was operating when the break occurred, then there may be some overflow due to pump coastdown after it trips.

If water level reaches about one foot in the condenser pit an annunciator alarms. If water level continues to rise and two of the three level switches trip, additional annunciators will alarm and the circulating pumps automatically stop. Even if the pumps did not automatically trip and the condenser room was flooded before operators manually trip the pumps, there are no components important to the PRA in the condenser room.

Considering the components affected and the low probability of a passive failure combined with failure of the flood protection pump trip logic, further consideration of circulating water system pipe or bellows breaks was not necessary.

Potential improvements

No flood initiator was identified that by itself causes core damage or containment failure. Random equipment failure or operator error unrelated to the flood is always required before core uncovery can occur. No plant modifications or procedure changes are currently planned. Plant staff and operators have been informed of the flooding potential and consequences. An NSP member of the IPE team provided the operators with classroom training on the IPE results including internal flooding.

F.E. 29 It is stated that for the discussion on loss of DHR, that DHR is defined as loss of Decay heat removal from the containment. Provide a discussion as to why heat removal was addressed in this manner and no consideration was given to the reactor core. Explain the impact on the results of the analysis using this approach.

In the IPE submittal, NSP defined the decay heat removal function as removal of decay heat from the containment. Another possible definition of the decay heat removal function would include two other functions, removal of decay heat from the reactor core to the containment and makeup of adequate coolant to keep the core covered with water. NSP did consider these functions as part of the IPE.

Under the alternate definition of the decay heat removal function, failure of decay heat removal would account for all level 1 results except LOCA outside containment and ATWS. A summary of where these accident classes are discussed in the IPE submittal is given below.

Section 3.4.2.1	Class 1A, Transient with failure of high pressure coolant makeup and failure to depressurize (TQUX).
Section 3.4.2.2	Class 1B, Station blackout.
Section 3.4.2.4	Class 1D, Transient with failure of all coolant makeup (TQUV).
Section 3.4.2.5	Class 2, Transient with failure of decay heat removal from the containment (TW).
Section 3.4.2.6	Class 3, LOCA.

Each of these sections discusses the important assumptions, initiating events, hardware failures, and human actions for the applicable accident class.

F.E. 30 Throughout the IPE credit has been given to recovery of instrument air. The value given appears to be based on a single incident of failure of relief valves. What consideration has been given recovery of loss of instrument air based on other failures (e.g., dryers)?

The recovery of instrument air was based on one recovery of instrument air. However, only a 50% credit was taken for this. Since this was based on only one event, no other consideration was given to other failures. However, other air failures (e.g. dryers) would be as easily recovered. The air dryer can be manually bypassed, and if necessary, complete areas of the plant can be isolated. This value was not analyzed in the detailed HRA analysis because it was already very high (>.1) and instrument air failure did not contribute significantly to the results.

F.E. 31 Section 3.4.4.2.2 (RHR) indicates that the RHRSW system heat exchanger discharge valves have their own "Dedicated air system." Please describe this system. Discuss how the IPE addressed the failure rate of the heat exchanger discharge values, i.e., failure to go open upon loss of air, and the value used for operator error to open the valves.

Each heat exchanger discharge valve has a small air compressor that ties into the air system to act as an auxiliary supply for normal operation. The discharge valves fail open on loss of air, this was the only failure rate modeled. The failure to open was determined to be 5.76E-3 per demand. No credit was taken for operators manually opening these valves. The fact that these valves fail open makes the auxiliary air compressor unimportant to the PRA.

F.E. 32 Other analyses have assumed RHR and Core spray pump failure while your assumption (Section 4.1.3) is that the pumps are expected to continue an adequate flow rate under degraded conditions. Discuss the impact of this assumption on DHR analysis and the IPE results vs. the assumption of RHR and core spray pump failure.

This assumption reduced the calculated core damage frequency by about 1E-5/yr. The operability of the RHR and core spray pumps after containment failure in Class 2 (TW) accidents is based on several assumptions. These assumptions are discussed individually below.

1. Loss of room, seal, or bearing cooling will not materially affect the performance of the RHR and core spray pumps.

   This conclusion is based on results from a test at the plant where these pumps were run for several hours without room or bearing cooling and the temperatures of the pump rooms and bearings were recorded. Also, the mechanical seals of these pumps are cooled for life extension purposes, but cooling is not required for pump operability.

2. The RHR and core spray pumps will continue to pump adequate flowrates to the vessel even when stated NPSH requirements are not met.

   This assumption is based on the makeup requirements at the time of containment failure in class 2 sequences being very small (< 100 gpm) compared to the rated capacity of an RHR or core spray pump. If the operating crew could not throttle the pump flow to maintain NPSH within limits (as directed by the EOPs), operation of these pumps would be intermittent as opposed to continuous. Low NPSH is not expected to cause any damage to the pumps during these brief periods of intermittent operation.

3. The release of energy and steam to the reactor building following containment venting or failure in class 2 sequences would not disable the RHR or core spray pumps.

   This conclusion is based on MAAP analysis which revealed conditions in the RHR and core spray pump rooms would not approach the environmentally qualified limits for the RHR and core spray pump motors whether the containment failed on overpressure in class 2 accidents or was vented in a controlled manner.

4. The radiation levels in the reactor building would not disable the RHR and core spray pumps.

   This assumption is supported by the Monticello Environmental Qualification program, which qualifies the RHR and core spray pumps for a source term as specified in NUREG-0737. This source term is essentially equivalent to that expected from a full core melt. Since the core would be intact at the time of containment failure in a class 2 accident, the radiation field was not anticipated to interfere with successful pump operation.

F.E. 33 Your discussion of loss of feedwater in Section 3.4.4.2.1 on main condenser refers to Section 3.3 and Table 3.3-4 wherein the failure probability of recovering feedwater is 0.11. This, as noted, has the effect of significantly reducing the total contribution of loss of feedwater events. Provide a summary of the loss of feedwater events from plant data which provided the genesis for the 8 out of 9 quickly recoverable ratio.

A summary of the loss of the feedwater events is attached. Scram number 35 was the one out of 9 that was assumed to not have a feedwater recovery.

DATE	SCRAM NUMBER	EVENT DESCRIPTION	COMMENTS
07-15-74	34	Makeup/reject valves open at same time causes loss of feedwater.	Operator error causes vacuum problem which led to hotwell level control problems. This in turn led to makeup/reject valves open at same time and pump runout. Feedwater recovered in 5 minutes. RCIC was manually started.
11-15-74	35	Failed valves in condensate demineralizer cause loss of feedwater.	Unknown how long it took to restore feed flow. Operator action prevented Group 1 isolation. Condensate pumps available.
08-31-75	37	Putting condensate demineralizer in service, loss of feed causes SCRAM. (Only one feedwater pump on initially)	Condensate demineralizer valve had sluggish operation causing low suction trip of RFP'S. The RFP could easily be restarted. Condensate pumps available.
02-23-77	46	Line problem causes load rejection. Fault on Sherco line circuit breaker 8N5 was open.	SRV's actuated. Maintenance in subyard contributed to problem. 8N12 out. Loss of power to 11, 12, 13, 14 bus. This related to SOE 82-01. Transformer 1R would not close on, out of synch. Feedwater recovery at 15 - 30 minutes.
03-28-79	58	Maintenance causes RFP trip, low level SCRAM	Condensate pump available, RFP restarted immediately.

DATE	SCRAM NUMBER	EVENT DESCRIPTION	COMMENTS
07-20-79	60	Feedwater level controller failure causes low level SCRAM	Feed pumps restarted in 10 minutes. Condensate pumps available.
07-23-79	61	Feedwater control failure causes low level SCRAM.	Feedwater pumps were manually tripped on high level. Immediate restart of RFP. Condensate pump available.
10-04-86	74	Loss of suction to RFP causes low level SCRAM (one RFP in service)	Loss of suction during maintenance. Feedwater restored in 15 minutes. Condensate pump available.
04-03-87	78	4KV breaker jarred causes feedwater pump trip, low level. (both pumps tripped)	Condensate pump tripped causing trip of feed pumps on low suction pressure. Feedwater restored in 1/2 hour. Condensate pump always available.

F.E. 34 The discussion (pg 3.4-38) of contributors to RHR system unavailability indicates that the possibility of redundant valves in wetwell and drywell spray and LPCI Mode can potentially limit significance of TORUS cooling valve failures along with manual operation of the valves, given the time frame (DAYS) available. However, it is not clear from the discussion that credit is or is not given for these subsequent actions. This scenario would be conservative if no credit is given for these actions only if procedures and training are in place for these actions, otherwise errors of commission might occur making it non-conservative. Provide a discussion addressing this concern and its impact on the DHR results. For those scenarios wherein time is of the essence (e.g., ATWS).

Monticello does not have procedures that direct the operators to use alternate means to return water to the torus if the torus cooling valves fail to open, so no credit was taken for these actions in the IPE.

F.E. 35 The analysis for loss of DHR indicates that if venting is required, the operators are instructed to maintain the containment pressure below 56 psig as opposed to depressurizing. Venting in this manner would allow continued operation of equipment in the reactor building by limiting the environmental impact. Since "venting" on this basis may be required more than once it is expected that the chances of failure of the system would increase. Please describe how multiple venting were addressed in your investigation and what increase in venting failure was observed. In addition discuss the probability of the vent valve failing open thereby increasing the environmental impact and subsequent failure of equipment. What is the impact on the results?

No assessment was made of multiple operation of the vent valves in the IPE. However, the failure of the containment vent function is almost totally dependent on support system availability and human error. Multiple demands for operation of the vent valves would not substantially alter the system reliability.

MAAP analysis was done for containment overpressure failure in the torus room. The conditions in the reactor building for this MAAP run would not have prevented RHR or Core Spray pumps from operating. Another MAAP run using intermittent containment venting between 56 psig and 46 psig drywell pressure also showed conditions where the RHR and Core Spray pumps would survive. These two runs appear to bound the reactor building effects of containment venting, whether done intermittently or once, with the vent valves remaining open.

F.E. 36 The paragraph under Class 1A on page 6-3 indicates that modifications are "under consideration" to provide power to the solenoid valves for the bottled nitrogen supply from an instrument panel (not Y20) that can be powered by an essential power supply or batteries (expected reduction 3.4-6/yr). This is about an 18% reduction in CDF. Is this a new consideration from your earlier analysis (1988)? Please describe your investigation into the implementation of this change including schedule considerations.

This is not a new consideration from the 1988 analysis. A modification to power the solenoid valves from DC power instrument bus Y80 is planned for completion during the February 1993 outage. A preliminary analysis showed the 3.4E-6/yr reduction, but an actual study has not been done nor has the PRA been updated.

F.E. 37 Is the extra time provided by the loadshed procedure changes identified on pg. 6-7 for Class 1B (SBO and HPCI/RCIC failure) responsible for the estimated reduction of 3.4E-6/yr or is this reduction tied to the recommendation for panel Y20. Please describe the genesis of expected reduction and its relation, if any, to that for panel Y20, and the total expected impact on the IPE results.

The recommendation to provide extra time by loadshed procedure changes is not tied to the Y20 recommendations in any way, since Y20 is AC powered. No comparative analysis was done between the two. The reason that both of the reductions came out to 3.4E-6/yr is that either of the changes will give the same benefit. The benefit of either recommendation is to help the operating crew to control pressure for up to 6 hours, giving more time to restore a diesel generator offsite power.

F.E. 38 It is not clear that the additional two hours that the load shed procedures will provide will impact the core damage frequency contributed to Class 1B by loss of HPCI and RCIC due to loss of station batteries (83%) to the degree indicated since as described in item #1 on page 3.4-9 the "offsite power and diesel generators were recovered in 6 hours for these sequences." Since the additional two hours will increase the total battery time to only six hours, please provide your assessment of the benefit derived from this procedure change identifying how the additional time results in this reduction.

Extending the battery life by two hours would lengthen the time available to recover either a diesel generator or offsite power, thus increasing the probability that some source of AC power could be recovered before the batteries deplete. This would decrease the core damage frequency for those sequences which contain battery depletion.

F.E. 39 Of the items (1 through 6) on pages 6-7,8 that were considered "to maximize the time" that the plant can survive the SBO event, please identify those that have been chosen for implementation, the expected time of implementation, the final benefits derived, and the rationale for selection.

All of these recommendations except item 3 were selected for implementation. The status of the selected items is discussed below. (This response does not represent a commitment by NSP to complete any of these projects.)

Item 1: operator training. Status: complete. Benefits: difficult to quantify, but this was a low cost item that was judged to be worth doing in spite of uncertain benefit. Rationale for selection: inexpensive.

Item 2: improve battery loadshedding procedures. Status: in progress. It is anticipated that this project will be completed in 1993. Benefits: lengthen time to recover a diesel generator or offsite power, thereby reducing core damage frequency. Rationale for selection: inexpensive and potentially beneficial to core damage frequency.

Item 4: AC independent power supply to battery chargers. Status: Under evaluation by plant staff to determine feasibility of this project. Benefits: could use the non-safety grade 480V diesel generator to maintain batteries charged during station blackout, thus reducing core damage frequency. Rationale for selection: potential for reduction in core damage frequency.

Item 5: fire water to RHR crosstie. Status: complete. Benefits: provides ability to supply water to the drywell sprays or LPCI during station blackout. Rationale for selection: This modification was already planned for other reasons.

Item 6: Modify power supply that supports SRV pneumatics. Status: A planned modification meets the intent of this recommendation. The modification is scheduled to be installed during the 1993 refueling outage. Benefits: increases diversity and redundancy of support systems for the SRVs. Rationale for selection: The plant staff wanted to do this modification for other reasons.

H.F. 1 The IPE submittal states, "With few exceptions, the plant evaluation and model quantification did not take credit for nonproceduralized operator actions." (page 3.1-18) Please provide a listing of such expected operator actions, including repair and recovery actions, and the rationale for taking credit for these nonproceduralized actions in the IPE.

Two nonproceduralized operator actions were used in quantification. The first was long-term hotwell make-up. Decay heat calculations showed that the CST volume was adequate for several days. This along with multiple sources for makeup and engineering judgement led to a value of 0.1.

The second operator action that was credited was to restore cooling water to air compressors after a loss of service water. A screening estimate of 0.01 was used in the IPE quantification given the time available to perform this action (days). NUREG/CR-4722 "Human Reliability Analysis" could be used to determine a value of 5.5E-5 for this action without a procedure.

It should also be noted that both of the operator actions have been made less important by changes at the plant. The new Revision 4 of the EOPs references a new procedure C.5-3203 "Use of Alternate Injection Systems for the RPV Makeup". A new plant air compressor has been added that has its own closed loop heat exchanger, making it independent of service water.

The recovery actions relating to offsite power and diesel generator recovery are all estimated based on industry experience and are too diverse to be covered by plant procedures directly.

H.F. 2 A limitation when operator actions are addressed in the fault trees is that dependencies between operator actions are difficult to model. The IPE treated operator errors occurring subsequent to an accident initiator in the system fault trees. (page 3.3-9) Please provide a brief discussion of how any dependencies which may exist between operator actions within individual accident sequences were addressed in the analysis.

In order to minimize the possibility of having multiple human error events in the same cutset, the number of human errors included on the fault trees was held to a minimum. Only those post-accident operator actions required to initiate systems were included in the fault trees. Operator actions in response to equipment failures were not included until sequence cutsets were generated. The cutsets were reviewed after sequence quantification and when more than one human error appeared in the same cutset, either independence of the human actions was confirmed, or a change was made to correctly model dependence between the human errors.

H.F. 3 In section 3.4 of the licensee's IPE submittal, information is provided concerning the most significant operator actions for each accident class. If available, please provide a listing which identifies the most significant operator actions and the percentage contribution of each to total core damage frequency, if known.

The table below lists the 5 most significant operator actions and their Fussel/Vesely ranking or percentage contribution to the total core damage frequency.

No.	Description	FV Rank
1	Operator fails to depressurize reactor (45 minutes)	22%
2	Operator fails to inject SLC/turbine trip initiator	3.1%
3	Operator dilutes boron by failing to control level	1.8%
4	Operator fails to inject SLC/MSIV closure initiator	1.2%
5	Operator fails to manually open SV-4234/35 (alternate N_2 supply)	1.0%

H.F. 4 Briefly summarize the experience of the IPE team and the review teams regarding human reliability assessment.

The IPE team contained two engineers that have attended an EPRI course on Human Reliability Analysis. One was an NSP engineer and the other was a consultant. One of the review team engineers has attended an INPO class on Task Analysis and an IEEE class on Human Factors. A member of the plant staff responsible for the control room design review was included on the review team.

B.E. 1 What version of the MAAP code was used in the IPE?

MAAP 3.0B, BWR version 7.0 was used for all of the success criteria, equipment survival, source term, and accident class benchmark evaluations, except that sections 7.2.3.3, 7.2.1.2, and 7.2.2.2 used intermediate revisions up to revision 7.03.

Version 7.02 was used for the sensitivity studies described in section 4.8.2.

B.E. 2 Numerous assumptions are made throughout the analysis. The bases for the assumptions are frequently not provided. For example, it is assumed that although NPSH is lost, the pump will continue to function adequately. This assumption could be optimistic considering that although it is likely that loss of NPSH will not immediately fail a pump, how long and at what capacity it will operate is uncertain. In addition, this assumption has a major impact on the analysis; that is, if it were assumed that the pumps fail, the results would be significantly affected. Provide bases or rationale for significant assumptions used in the analysis.

It is assumed that by "significant assumptions" the questioner means assumptions that are uncertain and which may have a large impact on the level 1 or level 2 results. The assumptions which are significant by these criteria are discussed individually below.

1. Control rod drive (CRD) hydraulic pumps are generally assumed to not be capable to inject sufficient quantities of water to prevent core damage. The basis for this assumption is the relatively low capacity of the CRD hydraulic system and scoping MAAP analysis which was inconclusive on the ability of CRD, working alone, to prevent core damage.

2. It is assumed that liner melt-through would be avoided if a vessel breach occurred at Monticello. The basis for this assumption is the presence of large sumps under the reactor combined with the relatively small volume of the core. These factors would prevent significant quantities of corium from contacting the containment wall. This assumption was tested with a sensitivity study (section 4.8.1.1).

3. It is assumed to be possible to arrest the core damage in vessel if coolant is injected within 100 minutes of the initiating event. The one hundred minutes is based on an analysis which calculates the time following relocation of the entire core into the vessel lower head to vaporize the water in the lower plenum and adiabatically heat up the debris to 2500°K when the RPV would also be substantially heated up. Section 4.8.1.3 performs a sensitivity analysis on this assumption by assuming no in-vessel recovery occurs.

4. It was assumed that corium on the concrete floor of the containment would be coolable if covered with water so that core-concrete interaction would not occur. This assumption is based on some simple thermodynamic calculations and was also tested with a sensitivity study (section 4.8.1.2).

5. Equipment in the RHR pump rooms is assumed to continue functioning after containment failure. The basis for this assumption is discussed in sections 4.1.3 and 7.3 of the IPE, and in the response to question F.E 32.

6. SRV accumulators were assumed to hold adequate pneumatic pressure to allow short term vessel depressurization (within the first hour), but not to maintain the vessel

7. When a containment overpressure failure occurs, the drywell is assumed to fail 50% of the time, the wetwell airspace 49.5% of the time and the wetwell waterspace 0.5% of the time. This is based on calculations which show approximately this distribution at the expected containment failure pressure.

8. For class 2 accidents (loss of decay heat removal), the containment failure size was assumed to be large. This is based on uncertainty over whether the hole would be just large enough to maintain a steady pressure, or whether a rupture would occur, opening a larger hole and rapidly depressurizing the containment. The large hole size was assumed because it is believed to provide the most limiting environment in the reactor building and the most severe release of radionuclides.

9. The ability of the RHR and core spray pumps to function when NPSH requirements are not met is addressed in the response to question F.E. 32.

B.E. 3 It is not clear that all types of dependencies have been considered in the back-end analysis. Consideration in regards to the effects of room cooling on equipment seems to have been incorporated into the analysis. Other types of dependencies do not seem to have been considered such as dual usage (e.g., use of LPCI and RHR when only one train is available), inventory control, fluid effects (e.g., high water temperature on pump seals and bearings), or other phenomenological effects. In addition, it is not clear if and where radiation effects were considered. Please provide a complete list of dependency considerations.

System Dependencies

Front-line system dependencies on support systems and initiating events were modeled in the Monticello IPE by use of the fault tree linking technique. A summary of system dependencies is given in tables 3.2-3, 3.2-4, and 3.2-5.

Multiple Use Systems

The RHR system was credited for three functions, LPCI, decay heat removal and containment spray. LPCI and decay heat removal can be accomplished simultaneously by either directing the LPCI flow through the RHR heat exchanger or by running RHR in torus cooling mode and periodically switching to LPCI mode to refill the vessel as needed. Containment spray is not credited simultaneously with vessel injection once vessel penetration has occurred. In addition, the pressure and temperature conditions are expected to be such that containment spray is prohibited after vessel failure.

RHR service water was credited for both decay heat removal from the RHR heat exchangers and reactor vessel injection via the RHR crosstie. In cases when RHR service water is used for injection to the vessel, the RHR system would have failed to perform in the LPCI mode. Thus RHR service water support of RHR in the torus cooling mode would probably be moot in these cases due to RHR system failures. Also, RHR service water could be used for cooling with intermittent switching to makeup as described above for RHR.

The control rod drive hydraulic system is credited for two functions, high pressure coolant makeup when an SRV is open and HPCI is also successful, and alternate boron injection when standby liquid control is unsuccessful in an ATWS. These two functions are never challenged in the same sequence.

Inventory Control, Fluid Effects, and Other Phenomenological Effects

The ability of the RHR and Core Spray systems to continue to function in the environment after containment failure is discussed in IPE sections 4.1.3 and 7.3, and in the response to question F.E.32.

Significant radiation fields would exist in the reactor building after core damage, and only the equipment qualified for this environment was credited.

The dependency of the turbine-driven high pressure coolant makeup pumps (HPCI and RCIC) on reactor pressure was modeled by not crediting these systems when the reactor is depressurized by a large or medium LOCA, steam line break, or by manual depressurization.

Phenomonelogical effects due to severe accident conditions are discussed in detail in section 4.4 of the IPE.

B.E. 4 Phenomenological effects resulting from the accident progression can have a large impact on the resultant source term. It is not clear how phenomenological effects were addressed in the CET quantification, particularly since small CETs were developed with supporting fault trees. It is not clear how the applicable containment failure modes and mechanisms were integrated into the accident progression of the CETs. Provide a discussion of "representative" pathways for each CET describing the accident progression and how containment failure occurs.

The following is a summation of an accident progression for each CET. A discussion of a representative path which leads to containment failure is provided as opposed to those which result in an intact containment. The majority of the sequences do result in a successful containment state, thus the discussion below may not reflect dominant level II sequences. The CET headings are discussed in section 4.5 of the IPE submittal.

CET for Class 1A

Class 1A accidents involve the loss of high pressure coolant inventory makeup with the reactor remaining at a high pressure (see Section 7.2.1.1). This representative pathway (Sequence 1A - 17) begins with a loss of feedwater and the failure of all high pressure injection systems. The containment successfully isolates. The containment is inerted, so combustion does not occur. ADS is inhibited, so the reactor vessel pressure remains high. Without high pressure injection, the core eventually melts through the reactor vessel bottom head and is ejected at high pressure into the pedestal. Vapor suppression is successful, so the suppression pool successfully accommodates the heat from the ejected core debris, and the containment pressure rises only a few psi. All of the core debris which exits the vessel is expected to be retained in the large sumps located in the pedestal area. In addition, with the vessel depressurized, a single LPCI pump begins injecting from the suppression pool; the LPCI flow pours through the hole in the vessel bottom and onto the core debris in the pedestal, providing debris cooling. Therefore, the potential for debris reaching the drywell shell and melting through the liner is very small and is assumed to be zero. Core concrete attack is not sufficient to fail the containment in the time frame covered in the analysis (40 hours). When torus water temperature reaches 110°F, a single loop of torus cooling is initiated and causes the drywell pressure to level out near 86 psia, after peaking at about 92 psia following reactor vessel failure. This is well below the failure pressure of 118 psia. Drywell gas temperature rises to less than 580°F at 40 hours into the sequence, much less than the 700°F which leads to thermal attack of the containment boundary.

CET for Class 1B

Class 1B accidents are station blackouts (see Section 7.2.3.1). It should be noted that for this accident class AC power recovery (either offsite or onsite) can have a significant influence on the outcome of the sequence. If recovered within the first few hours following loss of reactor makeup and fuel damage, recovery within the vessel may be possible. If recovered within approximately 36 hours, prevention of thermal and overpressure failure of containment can be accomplished. For the purposes of this discussion an extended loss of all offsite power and onsite AC power is assumed up through the point that containment failure is postulated.

This representative pathway (Sequence 1B - 22) begins with a station blackout, disabling all injection except HPCI and RCIC, which operate on battery power. The containment successfully isolates. The containment is inerted, so combustion does not occur. ADS is inhibited, so the reactor vessel pressure remains high. The batteries are depleted at four hours, failing HPCI and RCIC and leaving the reactor with no injection. The core eventually melts through the reactor vessel bottom head and is ejected into the pedestal at high pressure. Vapor suppression is successful, so the suppression pool successfully accommodates the heat from the ejected core debris, and the containment pressure rises only a few psi. Core concrete attack is not sufficient to fail the containment in the time frame covered in the analysis (40 hours). Drywell pressure shows a spike of 97 psia when the reactor vessel fails, considerably less than the containment failure pressure of 118 psia and rises slightly thereafter, reaching 104 psia 35.4 hours into the sequence, so no containment failure due to overpressure occurs. However, drywell gas temperature reaches 700°F at 35.4 hours, causing drywell failure due to thermal attack of the containment boundary.

CET for Class 1D

Class 1D accidents involve the loss of all reactor coolant inventory makeup (see Section 7.2.2.2). This representative pathway (Sequence 1D - 13) begins with closure of the MSIVs, followed by the failure of all injection systems. ADS is allowed to operate automatically to depressurize the vessel. The containment successfully isolates. The containment is inerted, so combustion does not happen. With no injection, the core melts through the vessel bottom head and pours into the pedestal at low pressure. All of the core debris which exits the vessel is expected to be retained in the large sumps located in the pedestal area. Therefore, the potential for debris reaching the drywell shell and melting through the liner is very small and is assumed to be zero. Core concrete attack is not sufficient to fail the containment in the time frame covered in the analysis (40 hours). Drywell pressure spikes to 46 psia when the reactor vessel fails, considerably less than the 118 psia assumed to cause drywell failure, and rises steadily thereafter, reaching just over 50 psia 34 hours into the sequence, so no containment failure due to overpressure occurs. However, the gas temperature in the drywell spikes to 250°F at vessel failure, drops back to 220°F, and then rises slowly throughout the sequence, eventually reaching 700°F at 34 hours, causing drywell failure due to thermal attack of the containment boundary.

CET for Class 2

Class 2 accidents entail the loss of containment heat removal (see Section 7.2.5.1). This representative pathway (Sequence 2 - 10) represents a loss of all containment heat removal in which both high-pressure (RCIC) and low-pressure (LPCI) injection systems are available, but only to inject water from the suppression pool; no source of water from outside the containment is used. The pathway begins with the closure of all MSIVs and failure of feedwater and CRD injection. RCIC is initiated by low level in the reactor, and the SRVs relieve steam to the suppression pool, maintaining reactor pressure near normal operating pressure; ADS is inhibited. When the pool temperature reaches 142 F, the operator begins using one SRV to gradually depressurize the reactor vessel per procedure, to stay within the suppression pool's heat capacity temperature limit curve. When reactor pressure becomes low enough, the LPCI system also can inject. As the pool temperature reaches 194°F, the reactor is brought to 70 psig and maintained at that pressure. RCIC becomes inoperable when the pool temperature reaches 200°F; after that time, makeup flow is supplied to the vessel by the LPCI system. The pressure and temperature in the drywell and wetwell continue to rise. After many hours, the drywell pressure reaches 70 psig; pneumatic control of the SRVs is lost, and they reclose. The reactor vessel repressurizes and LPCI can no longer inject to the vessel. Without makeup flow, the water level in the reactor begins to boil down. Finally, the rising drywell pressure reaches the failure pressure of 103 psig, causing the containment to fail in the drywell; the reactor level is still one foot above the top of active fuel. At this point the class 2 CET is entered. The drywell failure depressurizes the containment. No injection sources succeed for this sequence. Pneumatic control of the SRVs is regained as the drywell pressure drops, and the reactor vessel again depressurizes to 70 psig. Considerable inventory is lost through the SRVs during blowdown, and the core becomes uncovered. By this time, nearly two days have elapsed, and decay heat is low enough that five hours pass before the core finally melts through the vessel bottom and is ejected at low pressure into the failed containment. All of the core debris which exits the vessel is expected to be retained in the large sumps located in the pedestal area. Therefore, the potential for debris reaching the drywell shell and melting through the liner is very small and is assumed to be zero. Core concrete attack is not sufficient to fail the containment in the time frame covered in the analysis.

CET for Class 3

Class 3 accidents result in a large break in the primary system (see Section 7.2.6.3). In this representative pathway (Sequence 3 - 13), a break of 9.6 sq. in. occurs in the suction line to one of the recirculation pumps, causing the containment to isolate. The containment is inerted, so combustion does not happen. All injection systems fail. ADS is inhibited, but the reactor vessel depressurizes through the break. The water in the vessel boils off quickly, and the uncovered core melts through the bottom of the vessel and pours at low pressure into the pedestal, where it remains uncooled. All of the core debris which exits the vessel is expected to be retained in the large sumps located in the pedestal area. Therefore, the potential for debris reaching the drywell shell and melting through the liner is very small and is assumed to be zero. Core concrete attack is not sufficient to fail the containment in the time frame covered in the analysis (40 hours).

The temperature and pressure in the containment continue to rise, and in time the drywell gas temperature reaches 700°F, causing drywell failure due to thermal attack of the containment boundary. The drywell pressure is 63 psia at the time of containment failure.

CET for Class 4

Accident class 4 sequences are ATWS events (see Section 7.2.4.1). This representative pathway (Sequence 4 - 24) begins with the closure of all MSIVs; the scram function fails and the standby liquid control system is not actuated. Feedwater fails, but the single CRD pump which is already in operation continues to run. Within seconds, HPCI and RCIC are initiated and the recirculation pumps trip due to low level in the reactor; no other injection is available. The combined flow is sufficient to maintain indicated level about two feet below the top of active fuel, and core power drops to 28% of full power. With the MSIVs closed, the steam from the reactor is released through the SRVs and into the suppression pool. When the pool becomes saturated, the containment begins to pressurize and eventually fails on high pressure in the wetwell waterspace, disabling all injection systems. At this point the class 4 CET is entered. The core melts through the vessel bottom and is ejected at high pressure into the failed containment. Core concrete attack is not sufficient to fail the containment in the time frame covered in the analysis.

The phenomena which are addressed within the structure of the CET are discussed in Section 4.4 of the submittal.

B.E. 5 The description of accident progression is unclear, and insufficient descriptions of the CETs are provided. For example, for Class 1A which involves TQUX type sequences, it is not clear why the suppression pool scrubbing event was asked and not asked. From the documentation, for CET sequences 1A-3,4 and 5, the suppression pool scrubbing event is asked if WW venting successfully occurs and is not asked if venting is via the DW. However, it appears that with the reactor depressurized and successful vessel injection, core damage is arrested and vessel failure does not occur. Since there is not a LOCA involved and there is no vessel failure, and "releases" from the initially damaged core can only enter containment from the SRV's which directly release to the suppression pool. It would appear that the status of the vacuum breakers is immaterial in these instances; therefore, scrubbing is available regardless of the location of venting for these scenarios. Another example, it is not clear why only DW venting is asked when late vessel injection occurs using external sources. Would not RHR or WW venting or both be available, and therefore suppression pool scrubbing? Provide a discussion on accident sequence progression of "representative" pathways modeled in each CET addressing this event.

There are three questions here: (1) Why was wetwell scrubbing not credited in sequence 1A-04?, (2) Why is only drywell venting asked if late injection occurs via external sources?, and (3) Provide a discussion of level 2 accident sequence progression. These questions are answered individually.

1. Wetwell scrubbing should have been credited in sequence 1A-04. This sequence was truncated in the analysis because its frequency is less than 1E-9/yr, so the impact of this error is negligible.

2. Drywell venting is the only way containment pressure can be controlled when water is being injected to the containment from an external source. This is true because as water is added to the containment, the level of the suppression pool rises until the wetwell vent is submerged. Removing heat from the containment via torus cooling has limited benefit under these conditions because the non-condensible gases become compressed in the upper part of the drywell as water level continues to rise. The only alternative is to open the drywell vent.

3. Please see the response to question B.E. 4 for a discussion of representative accident sequences from each containment event tree.

B.E. 6 The CET for Class 1D shows that core damage is arrested in pathway 1D-5 which is similar to pathway 1A-5 for Class 1A CET. For pathway 1A-5, however, core damage is not arrested. Provide a discussion explaining the reason(s) for difference in damage state outcome.

This difference arises because of an error in the event trees that was not noticed. Sequence 1D-05 should not have arrested damage in the reactor vessel. The sequence frequency is about 2E-8/yr, so the impact of this error is negligible.

B.E. 7 The most likely location of containment failure was identified as either the wetwell vent bellows or drywell head. The type of failure, whether a leak, catastrophic rupture, that is, the size of the failure is not discussed. Provide size and rationale.

The size assumed for the containment failure depended on the type of sequence. As explained below, a sudden, large increase in containment pressure or temperature was assumed to lead to a large break, while a slow increase would produce a small leak. This reasoning was used in determining the release modes for the various sequences, except that in some cases where the hole size was uncertain, a large hole was assumed.

For sequences in which the failure was due to a gradual increase in the containment pressure or temperature, a leak was assumed to occur in either the drywell head or the vent bellows. For the drywell head, a slow increase in pressure would be expected to cause the closure bolts to stretch until the flanges began to separate; if there were insufficient gasket springback, a leak would then be expected to form which was just large enough to relieve the pressure. For the wetwell vent bellows, performance would be limited by the circumferential stresses due to internal pressure. The bellows are made of stainless steel and would not reach their ultimate stress limits until 253 psia. However, for a slow pressurization, leakage would probably occur prior to the pressure reaching this level, and so a small break was assumed when the wetwell bellows failed during such a sequence.

For sequences in which containment failure would be due to a sudden spike in pressure, it is possible that the total energy delivered to the structure would be sufficient to cause catastrophic failure. For such sequences, a large failure size was assumed.

The smallest break size sufficient to depressurize the containment can be calculated by assuming that pressurization is due to steaming caused by decay heat, and then calculating the choked flow area needed at the failure pressure to release that amount of steam. For Monticello at 24 hours, this calculation shows that a break size of a few square inches is just sufficient to relieve containment pressure, and this is the upper bound for a small break.

A large break is defined as one which is large enough to rapidly depressurize the containment. MAAP analyses using different break sizes showed that as long as the break was large enough to allow rapid depressurization, the fission product releases were not sensitive to the size of the break. For most of the source term MAAP cases, a failure area of 1.78 ft^2 (1.5 ft diameter) was used; this was large enough to cause rapid depressurization, and was convenient in that it is also the size of the drywell vent. For a few cases, the area corresponding to a complete circumferential break in the vent bellows was calculated and used (20 ft^2).

B.E. 8 Conditional failure probabilities are provided for containment failure in the drywell and wetwell with values of 0.5 and 0.005, respectively. What are the bases for these values?

The total conditional failure probability used for containment failure in the wetwell is 0.5; the value of 0.005 refers to failure below the wetwell water line (See the definition of WW in table 4.5.1.).

The conditional failure probabilities for the different locations are based on figure 4.4-5, the Monticello containment failure probability distribution. In the IPE, we always assumed that the containment would fail if the pressure reached 118 psia. Figure 4.4-5 shows that at that pressure, the failure is about equally likely to occur in the drywell or the wetwell airspace ("bellows"); the chance of failure in the wetwell water space is part of the "wetwell shell" probability, which is negligible. In order to capture any insights from a water space failure, a non-zero value was assigned to this probability. The values used for these conditional failure probabilities, based solely on pressure, are:

drywell failure	0.5
wetwell airspace failure	0.495
wetwell water space failure	0.005

B.E. 9 In the modeling of severe accidents, there is uncertainty in regards to the phenomena and therefore, the manner in which an accident will progress and the subsequent impact on containment performance and the source term. The assumptions associated with the various phenomena are varied among the experts and the available modeling codes. It is important, therefore, to be aware of the differences and uncertainties, particularly in relation to their potential impact on containment performance and source terms. A quantitative uncertainty analysis of the various phenomena is not required by Generic Letter 88-20 or NUREG-1335. A sensitivity analysis, however, of those parameters that have the largest effect on the likelihood or time of containment failure and the magnitude of the source term is requested. Suggested parameters are summarized in Table A.5 of NUREG-1335 with detailed information on the uncertainties provided in Volume 2 of NUREG/CR-4551 (supporting documents to NUREG-1150). Based on these discussions and the results of the Peach Bottom NUREG-1150 analysis, different assumptions appear to have been made in the Monticello IPE. It is not apparent that the various phenomenological uncertainties that could potentially occur at Monticello and their impact were considered in the IPE. For example, it appears that in-vessel core damage arrest was assumed to occur anytime vessel injection was successful. Success of core damage arrest is dependent on several factors: time of injection relative to vessel failure, fraction of core slumped, pressure in vessel, in-vessel steam explosions, core mobility, recriticality from flooding, etc. In addition, NUREG-1150 analysis of Peach Bottom found containment failure dominated by early dry-well failure from shell melt-through while it appears that this failure mechanism has a relatively small contribution in the Monticello IPE. It is important that the licensee be aware of and recognize the various uncertainties associated with the various phenomena, particularly in regards to their impact on containment performance and the potential source terms, and therefore, the identification of vulnerabilities and the development of an accident management program. Please provide a brief discussion of each of the parameters listed in Table A.5 that were not considered in the sensitivity analysis and the basis for this decision; that is, provide the rationale why the parameters and associated assumptions were not considered to have a large effect on containment performance and source term.

Analysis performed for Monticello indicates that enough of the core debris exiting the vessel will be retained within the pedestal sump to preclude a debris bed depth of sufficient magnitude to cause liner melt-through. This is the principal reason why liner melt-through is a small contributor to the Monticello IPE. In comparing Peach Bottom NUREG-1150 results to the Monticello IPE results, it is important to consider the difference in thermal power, and therefore in the volume of core debris, between the units (Peach Bottom 3292 MW, Monticello 1670 MW).

The main consequence of a liner melt-through would be to cause early drywell failures in sequences that would otherwise lead to late or no drywell failure. Note that in accident classes II and IV, liner melt-through is irrelevant because the containment fails prior to core damage. That is, for many of the sequences with large releases, liner melt-through is irrelevant because its contribution to an already large source term is insignificant.

In-vessel recovery is predicated on operator actions to depressurize the vessel within 100 minutes of core damage, allowing for low pressure injection (Section 4.22, Item 22). The one hundred minutes is based on an analysis which calculates the time required after relocation of the entire core into the vessel lower head to vaporize the water in the lower plenum and adiabatically heat up the debris to 2500°K, when the RPV would also be substantially heated up. Section 4.8.1.3 describes a sensitivity analysis on this assumption by assuming no in-vessel recovery occurs.

The issues in NUREG-1335 Table A.5 were addressed as summarized in the following table.

CONSIDERATIONS FROM NUREG-1335 TABLE A.5

Performance of containment heat removal systems during core meltdown accidents	The Level 2 results for ex-vessel sequences are not sensitive to the performance of containment heat removal systems such as RHR because of EOP instructions to flood the containment. Flooding leads to the need for drywell venting and therefore to releases through the vents, regardless of the status of RHR. Furthermore, neither the CETs nor the source term MAAP cases take credit for all of the systems which can be used for containment heat removal, and therefore the IPE results are conservative in this respect. The effect of this conservatism was gauged by reviewing those sequences in which all containment heat removal systems failed. Their combined probability is small enough that even if all of them were made no-release cases by including the neglected heat removal systems, the final source term results in Figure 4.7-1 would remain unchanged.
IN-VESSEL PHENOMENA:	
H_2 production and combustion in containment	Hydrogen combustion is not an important sensitivity consideration in an inerted containment, but the issue is addressed in Section 4.4.10. The IPE simply assumes that if the core melts into a deinerted containment, the containment fails from hydrogen combustion. Even with this conservative approach, combustion accounts for only 1% of the containment failures at Monticello, so no further sensitivity study is warranted. Since overpressure failures due to hydrogen production are possible even in an inert containment, sensitivity to the amount of hydrogen produced was examined in the MAAP sensitivity study in Section 4.8.2.1.
Induced failure of the reactor coolant system pressure boundary	Not applicable (PWR issue).
Core relocation characteristics	These effects are addressed by the MAAP sensitivity studies in section 4.8.2.1 (FCRBLK) and 4.8.2.4 (FMAXCP).
Mode of reactor vessel melt-through	This is discussed in the evaluation of thrust forces due to RPV blowdown in Section 4.4.2.
Fuel/coolant interactions	In-vessel and ex-vessel steam explosions are discussed in Section 4.4.3.

EX-VESSEL PHENOMENA:	
Direct containment heating concerns	Direct containment heating is discussed in Section 4.4.8.
Potential for early containment failure due to pressure load	This is discussed in Section 4.4.6 of the report. Related discussions also appear in Sections 4.4.3 (ex-vessel steam explosions), 7.1.5 (the number of wetwell-drywell vacuum breakers needed to prevent early containment overpressurization during a LOCA blowdown), and 4.8.2.1 (uncertainty in hydrogen production and its potential to overpressurize containment).
Potential for early containment failure due to direct contact by core debris	The potential for liner melt-through at Monticello is addressed in Section 4.4.7, and the sensitivity in IPE results to the liner melt-through question is examined in Section 4.8.1.1. Containment penetration response to high temperatures is discussed in Section 4.4.4. The IPE simply assumed that if the containment temperature reached 700°F, the containment failed. This mode of failure was sufficiently rare (1%) that further study was not warranted.
Long-term core-concrete interactions:	Core-concrete interaction is discussed in Section 4.4.9. In addition, the sensitivity of IPE results to the assumptions made about core-concrete interaction is examined in Section 4.8.1.2.
-water availability	Both dry and wet cases were examined with MAAP.
-debris coolability	Sensitivity to debris coolability is addressed in Section 4.8.2.5, "Coolability of Debris in Containment". (Note that this section is mis-numbered in the report; it begins on page 4.8-10.)

B.E. 10 A rationale for the percent of radionuclides released for the three release categories is not provided. Provide bases for categorization and selection of percent releases.

The release categories are defined according to the amount of volatile fission products released from the containment: less than 2% of the total inventory, 2% to 10%, or more than 10%. These ranges were selected based on the level 2 analysis, indicating where results were clustered together and to reflect an approximate step change in order of magnitude of released fission products. These ranges are also approximately the same as those used in the IDCOR study.

B.E. 11 A rationale for the grouping of release modes (e.g., Table 4.7-2) is not provided. Provide bases for selection of "representative" release mode and the basis for grouping of remaining release modes into the modeled ones.

The release modes were grouped based on similarities in expected releases. The release mode evaluated from each group was the one that was believed to produce the greatest release. This was done to make effective use of computer analysis to evaluate the source term. Below is the rationale used for each grouping.

Release mode A4 represents containment intact with reactor vessel breach. This is expected to bound the consequences of release mode A1, which is arrest in vessel with containment intact. No release is expected in either release mode. Release mode A4 was evaluated to confirm this belief.

Release mode A6 is drywell venting with corium outside the vessel. This is expected to bound release modes A2, A3, A5 and B2. Release modes A2, A5 and B2 are vented or uncontrolled releases through the wetwell airspace. These scrubbed releases are judged to be less severe than those from release mode A6. Release mode A3 is the same as release mode A6, except there is no vessel breach in A3.

Release mode C8 is a large early failure. Release mode C7 is the same except that the failure size is small. Release mode C9 is also an early small failure. Both C7 and C9 are expected to be bounded by the large failure of release mode C8.

Release modes C12 and C11 are the same except C11 is a small failure whereas C12 is a large failure. C12 is expected to bound C11.

Release modes D1, D3, and D5 are all late failures of the containment with small openings. D5 was evaluated by itself because it applies to a long-term station blackout, which is an important sequence at Monticello. The other two, D1 and D3, were evaluated together.

Release mode E1 is unisolated ISLOCA and release mode E2 is containment isolation failure. It is judged that the ISLOCA release, which transports radioactivity directly from the vessel to the reactor building, would be more severe than failure of containment isolation.

B.E. 12 Table 4.7-1 provides results of the fission product release rate for nine different CET end states. It is not clear if calculations were only performed for these cases, and if so, why these cases. Provide description of what end states were analyzed and the rationale for the selection.

The various release modes in the CETs were divided into eight groups, and the most severe release mode within each group was identified as described in the response to question B.E. 11. For each group, a bounding source term analysis was done by characterizing the source term for the most severe release mode in the group, and then assigning this source term to all of the end states in the group. Taking this approach made it possible to reasonably characterize the overall source term by evaluating only these eight bounding end states.

The representative sequence selection process screening criteria were as follows:

- Sequences were to be considered which contribute more than 5% of the total core damage frequency.
- Sequences were to be considered which had event frequencies greater than 1E-6/reactor year.
- Sequences were to be considered that had characteristics (order/timing of events, equipment availability/performance, operator action limitations, etc.) which would tend to maximize the potential severity of fission product releases.

If neither of the first two of these criteria could be fulfilled for a given release mode, the third criterion provides the means to perform a sequence evaluation for each release mode.

B.E. 13 Why are there two separate groupings of release modes A4?

Release mode A4 is not divided into two separate groupings; it is a single grouping with a total radionuclide release frequency of 1.3E-5/year for internal events and 3.3E-6 for internal floods. This may not be clear in tables 4.7-2 and 4.7-3, which show the results from nine separate MAAP cases. Two of the cases shown, MPB051/91 and MPB052/91, fall into release mode A4. They do not represent two separate subcategories; they are simply two separate examples of the same release mode.

B.E. 14 The results of the back-end analysis indicate that approximately 60% of the core damage frequency results in no releases. The basis for this conclusion is not apparent from the documentation provided, particularly in relation to the CETs. Provide a discussion of why such a large percent of the core damage sequences result in no release.

This result is due primarily to three items discussed in the IPE report: first, that liner melt-through is not expected to occur at Monticello; second, that molten core-concrete interaction is unlikely to fail the containment at Monticello; and third, that credit was taken for in-vessel arrest of a damaged core.

Liner melt-through: A plant-specific evaluation of this issue is discussed in section 4.4.7 of the report. In brief, it was found that the containment sumps at Monticello are large in relation to the size of the core. The volume of corium expected to be released into the pedestal when the vessel fails is not enough to overflow the sumps, and therefore molten corium will not contact the liner.

Molten core-concrete interaction (MCCI): This is discussed in section 4.4.9 of the report. For Monticello, it is possible that MCCI could generate enough non-condensible gases to overpressurize the containment in some sequences; however, should it exit the vessel, the debris is assumed to collect in the sump in a coolable configuration, provided adequate water is supplied through vessel injection systems. Since most ex-vessel core damage sequences are Class 1A (core melt at high pressure) or Class 1B (station blackout), recovery of injection systems for debris cooling is likely prior to containment failure. This reduces the possibility of releases due to MCCI.

Arrest-in-vessel: If injection were recovered within 100 minutes of the initiating event, it was assumed that the damaged core would be cooled and contained within the vessel.

Because of the importance of these three items, sensitivity studies were performed in order to understand the extent of their impact on the IPE results. These studies and their results are described in section 4.8.1 of the report.

B.E. 15 The results of the back-end analysis indicate that, for example, the containment failure is dominated by overpressure and drywell venting with other types of containment failure contributing less than 2% each. The unique safety features and insights provided in Section 6.0 are more in relation to the core damage frequency. The contributors for why the containment failure is dominated by overpressurization and drywell venting is not provided. What are the events driving these results? Provide insights, or important features, that are causing overpressure to be dominant and other failure modes to have little contribution.

Containment failure is dominated by overpressurization and drywell venting both because of features which limit the contribution of other failure modes and because of the nature of those sequences which do lead to containment failure.

Liner meltthrough does not contribute to containment failure at Monticello because the containment sumps are large in relation to the size of the core. Compared to Peach Bottom, for example, the Monticello sumps are slightly larger, but the reactor core is about half the size of the Peach Bottom core. As a result, the volume of corium released when the vessel fails is not expected to overflow the sumps at Monticello, and therefore will not contact and melt the liner. This is discussed in section 4.4.7 of the report. In addition, the containment is unlikely to fail due to molten core-concrete interaction (MCCI), as described in section 4.4.9.

Drywell venting is a more common failure mode than wetwell venting in part because of cases in which external injection is used to flood the containment. In such cases, the rising water level compresses the containment atmosphere enough that the pressure must be relieved by venting. The wetwell vents would be under water at that point, so the drywell vents must be used. Note that because of this, many of the drywell venting sequences actually represent scrubbed releases.

Overpressurization is a dominant failure mode in part because some of the equipment failures which lead to core damage will also disable the containment vents. The containment vents require instrument air in order to operate, and the compressors in that system are cooled by the service water system. If a core damage sequence includes failure of the service water system, then when that sequence is transferred to the level 2 analysis it must be assumed that the containment vents will not operate. If the level 2 analysis then requires venting to relieve pressure, the containment will fail on overpressure.

B.E. 16 How does the definition of release timing used in the back-end analysis compare with the release timing definition used, for instance, in NUREG-1150; early - up to and including vessel failure, and late - after vessel failure, regardless of time of initiator?

The definition of release timing used in the back-end analysis is relative to the time of the initiator; in NUREG-1150, the release timing definition is relative to the timing of vessel failure. The NUREG-1150 release timing definition is addressed by the release modes defined in section 4.3.3, where release mode C corresponds to NUREG-1150 release timing "early", and release mode D corresponds to NUREG-1150 release timing "late".

B.E. 17 In several places in the back-end analysis, the error value used for an operator action is stated to be lower than the value used in the Level 1 for the same action because the operator has more time. Time is not the only factor influencing operator performance. Provide descriptions of the performance shaping factors used in justifying the selection of lower values for these operator actions in the back-end analysis.

Different error values were used in three cases. They are listed below with the level 2 probability, Fussel/Vesely, and Risk Achievement Worth rankings.

	Prob	F/V	RAW
"Failure of hotwell makeup" replaced "service water not crosstied to hotwell."	.1	4.51E-4	1.0
Operator does not open RHRSW-RHR Crosstie was multiplied by a recovery factor in Level 2	.25	3.56E-4	1.0
Operator fails to depressurize reactor in 45 minutes was multiplied by scaling factor to increase the time to 100 minutes	1E-4	3.63E-4	1.33

For the first two it seemed logical from an operator's standpoint to assume a change in probability due to the longer time frame. However, when the F/V and RAW were calculated it showed that these events were not significant and led to no insights.

The last error value met the guidelines for a detailed Human Reliability Analysis. The only performance shaping factors that required change were the time and level of stress. The level of stress was increased from moderately high to high, due to the core damage. These changes led to a recovery factor about an order of magnitude lower than in Level 1, and similar to the assumed Level 2 value.

ATTACHMENT 1:

EXCERPT FROM MOTOR - OPERATED VALVE COMMON CAUSE FAILURE CALCULATIONS

CALCULATIONAL FORM
NUCLEAR ANALYSIS DEPARTMENT
FORM 17-3810(10-82)

NSP Northern States Power Company

SUBJECT MOV CC SHEET NO 1 OF 7

PREPARED BY CAB DATE 12/4/91 VERIFIED BY _____ DATE _____

Objective

This file contains the common cause calculation for

The common cause is summarized in folder II.SMN.91.007

Calculation

This calculation uses the common cause (section 6) part of the procedure in section 4 of Calculation file II.SMN.91.008 with some changes to ensure nonzero probabilities.

The following shows the formulas used:

1. Determine n(K,a), n(K,p), n(S,a) and n(S,p)

This is done by reviewing industry data and determining each value.

n(K,a) ≡ The number of actual failures involving K components
n(K,p) ≡ " " " potential " " " "
n(S,a) ≡ " " " actual single Common Cause failures
n(S,p) ≡ " " " potential " " " "

It should be noted that n(1,a) + n(S,a), and n(1,p) & n(S,p) are treated the same in the analysis.

2. Calculate Sum(K)

$$Sum(K) = K[n(K,a) + .1n(K,p)] + [K+1][n(K+1,a) + .1n(K+1,p)] + \cdots + m[n(m,a) + .1n(m,p)]$$

m ≡ Common cause group population
K ≡ number of components within population m $K \le m$

For 6 component common cause:

$$Sum(6) = 6[n(6,a) + .1n(6,p)]$$
$$Sum(5) = Sum(6) + 5[n(5,a) + .1n(5,p)]$$
$$Sum(4) = Sum(5) + 4[n(4,a) + .1n(4,p)]$$
$$Sum(3) = Sum(4) + 3[n(3,a) + .1n(3,p)]$$
$$Sum(2) = Sum(3) + 2[n(2,a) + .1n(2,p)]$$
$$Sum(1) = Sum(2) + n(1,a) + .1n(1,p)$$

3 Calculate MGL Factors

$\beta = [\,sum(2) + .5\,] \,/\, [\,sum(1) + n(s,a) + .1n(s,p)\,]$
$\gamma = [\,sum(3) + .5\,] \,/\, [\,sum(2) + 1\,]$
$\delta = [\,sum(4) + .5\,] \,/\, [\,sum(3) + 1\,]$
$\epsilon = [\,sum(5) + .5\,] \,/\, [\,sum(4) + 1\,]$
$\zeta = [\,sum(6) + .5\,] \,/\, [\,sum(5) + 1\,]$
$\eta = 1$

The above example is for a 6 component system. These equations are not the same as the referenced equations because the referenced equations will result in zero probabilities for some common cause basic events. The above change is to add .5 to sum(K) in the numerator an 1.0 to sum(K) in the denominator to account for the fact that the data is limited. See folder II.SMN.91.008 section 3 calculation for a more detailed explanation of the change to the equations in section 4 of that folder.

4. Common Cause Probabilities

The base equation is:

$$Q_K = \frac{1}{\binom{m-1}{K-1}} \left(\prod_{i=1}^{K} \rho_i \right) (1 - \rho_{K+1})\, Q_t$$

Reference: NUREG/CR-4780 page 3-19 Table 3-1

$Q_K \equiv$ probability of a basic event involving K specific components $1 \le K \le m$
$Q_t \equiv$ is the total failure probability of component $A = \sum_{K=1}^{m} \binom{m-1}{K-1} Q_K$
$\binom{m-1}{K-1} \equiv [(m-1)!] \,/\, [(m-K)!\,(K-1)!]$
$K \equiv$ number of components within population m $K \le m$
$m =$ total number of components in the common cause group
$\rho_1 = 1,\ \rho_2 = \beta,\ \rho_3 = \gamma, \ldots, \rho_{m+1} = 0$

For an 8 component common cause:

# Comp	Eq
1	$Q_t(1-\beta)$
2	$Q_t\beta(1-\gamma)/7$
3	$Q_t\beta\gamma(1-\delta)/21$
4	$Q_t\beta\gamma\delta(1-\epsilon)/35$
5	$Q_t\beta\gamma\delta\epsilon(1-\zeta)/35$
6	$Q_t\beta\gamma\delta\epsilon\zeta(1-\eta)/21$
7	$Q_t\beta\gamma\delta\epsilon\zeta\eta(1-\theta)/7$
8	$Q_t\beta\gamma\delta\epsilon\zeta\eta\theta$

This folder will calculate the factor which is multiplied to Q_t for each component.

CALCULATIONAL FORM
NUCLEAR ANALYSIS DEPARTMEI
FORM 17-3810(10-82)

NSP Northern States Power Company

SUBJECT _____ SHEET NO 3 OF 7

PREPARED BY CTB DATE 12/4/91 VERIFIED BY _____ DATE _____

For ease of use the $\binom{m-1}{k-1}$ factor will be determined for different m and k values.

m	k	$(m-1)!/[(m-k)!(k-1)!]$	
2	1	$(2-1)!/[(2-1)!(1-1)!] = 1/(1*1) = 1$	2 components
"	2	$(2-1)!/[(2-2)!(2-1)!] = 1/(1*1) = 1$	
3	1	$(3-1)!/[(3-1)!(1-1)!] = 2/(2*1) = 1$	3 components
"	2	$(3-1)!/[(3-2)!(2-1)!] = 2/(1*1) = 2$	
"	3	$(3-1)!/[(3-3)!(3-1)!] = 2/(1*2) = 1$	
4	1	$(4-1)!/[(4-1)!(1-1)!] = 6/(6*1) = 1$	4 components
"	2	$(4-1)!/[(4-2)!(2-1)!] = 6/(2*1) = 3$	
"	3	$(4-1)!/[(4-3)!(3-1)!] = 6/(1*2) = 3$	
"	4	$(4-1)!/[(4-4)!(4-1)!] = 6/(1*6) = 1$	
6	1	$(6-1)!/[(6-1)!(1-1)!] = 120/(120*1) = 1$	6 components
"	2	$(6-1)!/[(6-2)!(2-1)!] = 120/(24*1) = 5$	
"	3	$(6-1)!/[(6-3)!(3-1)!] = 120/(6*2) = 10$	
"	4	$(6-1)!/[(6-4)!(4-1)!] = 120/(2*6) = 10$	
"	5	$(6-1)!/[(6-5)!(5-1)!] = 120/(1*24) = 5$	
"	6	$(6-1)!/[(6-6)!(6-1)!] = 120/(1*120) = 1$	
8	1	$(8-1)!/[(8-1)!(1-1)!] = 5040/(5040*1) = 1$	8 component
"	2	$(8-1)!/[(8-2)!(2-1)!] = 5040/(720*1) = 7$	
"	3	$(8-1)!/[(8-3)!(3-1)!] = 5040/(120*2) = 21$	
"	4	$(8-1)!/[(8-4)!(4-1)!] = 5040/(24*6) = 35$	
"	5	$(8-1)!/[(8-5)!(5-1)!] = 5040/(6*24) = 35$	
"	6	$(8-1)!/[(8-6)!(6-1)!] = 5040/(2*120) = 21$	
"	7	$(8-1)!/[(8-7)!(7-1)!] = 5040/(1*720) = 7$	
"	8	$(8-1)!/[(8-8)!(8-1)!] = 5040/(1*5040) = 1$	

$(1-1)! = 0! = 1$
$(2-1)! = 1! = 1$
$(3-1)! = 2! = 2$
$(4-1)! = 3! = 6$
$(5-1)! = 4! = 24$
$(6-1)! = 5! = 120$
$(7-1)! = 6! = 720$
$(8-1)! = 7! = 5{,}040$

5	1	$(5-1)!/[(5-1)!(1-1)!] = 24/(24*1) = 1$	5 component
"	2	$(5-1)!/[(5-2)!(2-1)!] = 24/(6*1) = 4$	
"	3	$(5-1)!/[(5-3)!(3-1)!] = 24/(2*2) = 6$	
"	4	$(5-1)!/[(5-4)!(4-1)!] = 24/(1*6) = 4$	
"	5	$(5-1)!/[(5-5)!(5-1)!] = 24(1*24) = 1$	

CALCULATIONAL FORM
NUCLEAR ANALYSIS DEPARTMENT
FORM 17-3810(10-82)

Northern States Power Company

SUBJECT _____ SHEET NO 5 OF 7

PREPARED BY LSB DATE 12/4/91 VERIFIED BY _____ DATE _____

Plant	Date	Actual Failure	Potential Failure	NP-3367 Table 3-1 Source (see section 3)
Dresden 2	8/73	2	0	sheet 13 of 23
Vermont Yankee	2/76	2	0	13
Browns Ferry 2	12/74	1	4	14
Pilgrim	9/74	2	0	14
Vermont Yankee	5/76	0	2	15
Dresden 3	9/75	2	0	15
Browns Ferry	9/74	1	2	16
Hatch 2	9/78	2	0	16
Pilgrim	7/79	2	0	17
Hatch 2	5/80	2	0	17
Hatch 2	5/82	2	0	17
Dresden 2	10/73	0	2	17
Dresden 2	5/75	2	0	19
Cooper	10/80	1	2	19
Vermont Yankee	9/76	0	2	19
Dresden 2	8/73	2	0	19
Dresden 1	10/78	0	2	20
Pilgrim	10/81	0	2	21
Brunswick 1	11/76	1	2	21
Millstone 1	5/71	3	0	22
Pilgrim	4/73	0	2	22

$n(5,a) = 1$ $n(4,a) = 1$ $n(3,a) = 1$ $n(2,a) = 29$ $n(1,a) = 12$ $n(s,a) = 788$
$n(13,p) = 1$ $n(4,p) = 5$ $n(3,p) = 2$ $n(2,p) = 10$ $n(1,p) = 0$ $n(s,p) = 49$

2. Sum's 5 component $n(5,p) = n(13,p) = 1$ potential for 5 is assumed to be equal to the sum of higher #'s listed.

$Sum(5) = 5[n(5,a) + .1\, n(5,p)] = 5[1 + .1(1)] = 5.5$
$Sum(4) = sum(5) + 4[n(4,a) + .1\, n(4,p)] = 5.5 + 4[1 + .1(5)] = 11.5$
$Sum(3) = sum(4) + 3[n(3,a) + .1\, n(3,p)] = 11.5 + 3[1 + .1(2)] = 15.1$
$Sum(2) = sum(3) + 2[n(2,a) + .1\, n(2,p)] = 15.1 + 2[29 + .1(10)] = 75.1$
$Sum(1) = sum(2) + n(1,a) + .1\, n(1,p) = 75.1 + 12 + .1(0) = 87.1$

3. MGL 5 components

$\epsilon = [sum(5) + .5]/[sum(4) + 1] = [5.5 + .5]/[11.5 + 1] = .48$
$\delta = [sum(4) + .5]/[sum(3) + 1] = [11.5 + .5]/[15.1 + 1] = .75$
$\gamma = [sum(3) + .5]/[sum(2) + 1] = [15.1 + .5]/[75.1 + 1] = .20$
$\beta = [sum(2) + .5]/[sum(1) + n(s,a) + .1\, n(s,p) + 1] = [75.1 + .5]/[87.1 + 788 + .1(49) + 1] = .086$

CALCULATIONAL FORM
NUCLEAR ANALYSIS DEPARTMENT
FORM 17-3810(10-82)

Northern States Power Company

SUBJECT _____ SHEET NO 4 OF 7

PREPARED BY CAB DATE 12/4/91 VERIFIED BY _____ DATE _____

1. Determine n's

See reference EPRI report NP-3967 in section 3 of this folder.

$n(S,a) = FA + F + FOA + FOM + FO + FCA + FC$
$= 67 + 82 + 216 + 1 + 155 + 155 + 112$
$= 788$

(Page 3-37 of NP3967) Linear Event Category

$n(p,a) = PTO + PFA + PF + PFOA + PFO + PFCA + PFC$
$= 2 + 8 + 17 + 3 + 5 + 2 + 12$
$= 49$

Plant	Date	Actual Failures	Potential Failures	NP-3967 - Table 3-10 Source (Section 3)
Cook 2	1/79	1	3	Sheet 1 of 23
Turkey Point 3	4/79	2	0	" 1 "
Arkansas One	4/80	2	0	" 1 "
Palisades	6/71	1	4	" 2 "
Oconee 2	10/75	1	4	2
Trojan	10/76	1	3	" 3 "
North Anna	8/78	2	0	" 3 "
Kewaunee	9/75	2	0	" 4 "
Zion 2	10/75	2	0	" 4 "
Main Yankee	2/75	2	0	" 4 "
Salem 1	1/77	2	0	" 4 "
Arkansas 1	8/81	2	0	" 5 "
Oconee 1	11/75	2	0	" 5 "
Oconee 2	12/75	2	0	" 5 "
Rancho Seco	11/76	2	0	" 5 "
Oconee 1	10/73	2	0	" 7 "
Zion 1	6/75	2	0	" 7 "
Cook 1	11/77	2	0	" 7 "
Trojan	1/76	2	0	" 8 "
Indian Point 2	5/78	2	0	" 8 "
Oconee 2	12/79	2	0	" 10 "
Surry 2	12/80	2	0	" 10 "
Cook 1	3/81	5	0	" 10 "
Monticello	7/72	1	13	" 11 "
Browns Ferry 2	12/79	1	2	" 11 "
Millstone 1	1/71	4	0	" 11 "
Browns Ferry 3	5/75	1	4	" 11 "
Robinson 2	1/81	1	4	" 12 "
Surry 2	7/81	2	0	" 12 "

CALCULATIONAL FORM
NUCLEAR ANALYSIS DEPARTMENT
FORM 17-3810(10-82)

Northern States Power Company

SUBJECT _____ SHEET NO 6 OF 7

PREPARED BY CFB DATE 12/4/91 VERIFIED BY _____ DATE _____

4. Probabilities 5 component

# Comp	Eq for Q_k				
1	$Q_t(1-\beta)$	=	$Q_t(1-.086)$	=	$.91\ Q_t$
2	$Q_t\beta(1-\gamma)/4$	=	$Q_t(.086)(1-.2)/4$	=	$.020\ Q_t$
3	$Q_t\beta\gamma(1-\delta)/6$	=	$Q_t(.086)(.2)(1-.75)/6$	=	$.00072\ Q_t$
4	$Q_t\beta\gamma\delta(1-\epsilon)/4$	=	$Q_t(.086)(.2)(.75)(1-.48)/4$	=	$.0017\ Q_t$
5	$Q_t\beta\gamma\delta\epsilon$	=	$Q_t(.086)(.2)(.75)(.48)$	=	$.0062\ Q_t$

2. Sum's 4 component

$n(4,a) = n(5,a) + n(4,a) = 1+1 = 2$
$n(4,p) = n(3,p) + n(4,p) = 1+5 = 6$
} add the higher number of components to $n(4,a) + n(4,p)$

$sum(4) = 4[n(4,a) + .1n(4,p)] = 4(2+.1(6)] = 10.4$
$sum(3) = sum(4) + 3[n(3,a) + .1n(3,p)] = 10.4+3[1+.1(2)] = 14$
$sum(2) = sum(3) + 2[n(2,a) + .1n(2,p)] = 14+2[29+.1(10)] = 74$
$sum(1) = sum(2) + n(1,a) + .1n(1,p) = 74+12+.1(0) = 86$

3. MGL 4 component

$\delta = [sum(4)+.5]/[sum(3)+1] = [10.4+.5]/[14+1] = .73$
$\gamma = [sum(3)+.5]/[sum(2)+1] = [14+.5]/[74+1] = .19$
$\beta = [sum(2)+.5]/[sum(1)+n(5,a)+.1n(5,p)+1] = [74+.5]/[86+788+.1(49)+1] = .085$

4 Probabilities 4 component

# Comp	Eq for Q_k				
1	$Q_t(1-\beta)$	=	$Q_t(1-.085)$	=	$.91\ Q_t$
2	$Q_t\beta(1-\gamma)/3$	=	$Q_t(.085)(1-.19)/3$	=	$.023\ Q_t$
3	$Q_t\beta\gamma(1-\delta)/3$	=	$Q_t(.085)(.19)(1-.73)/3$	=	$.0015\ Q_t$
4	$Q_t\beta\gamma\delta$	=	$Q_t(.085)(.19)(.73)$	=	$.012\ Q_t$

CALCULATIONAL FORM
NUCLEAR ANALYSIS DEPARTMENT
FORM 17-3810(10-82)

Northern States Power Company

SUBJECT _____ SHEET NO 7 OF 7

PREPARED BY CAB DATE 12/4/91 VERIFIED BY _____ DATE _____

2. Sums 3 component

$n(3,a) = n(5,a) + n(4,a) + n(3,a) = 1+1+1 = 3$
$n(3,p) = n(13,p) + n(4,p) + n(3,p) = 1+5+2 = 8$
} $n(3,a)+n(3,p)$ are assumed to be equal to the sum of higher n's.

$sum(3) = 3[n(3,a) + .1\,n(3,p)] = 3[3 + .1(8)] = 11.4$
$Sum(2) = Sum(3) + 2[n(2,a) + .1\,n(2,p)] = 11.4 + 2[29 + .1(10)] = 71.4$
$Sum(1) = Sum(2) + n(1,a) + .1\,n(1,p) = 71.4 + 12 + .1(0) = 83.4$

3. MGL 3 component

$\gamma = [sum(3) + .5]/[sum(2) + 1] = [11.4 + .5]/[71.4 + 1] = .16$
$\beta = [sum(2) + .5]/[sum(1) + n(5,a) + .1\,n(5,p) + 1] = [71.4 + .5]/[83.4 + 788 + (.1)(49) + 1] = .082$

4. Probabilities

# Comp	Eq for Q_k		
1	$q_t(1-\beta)$	$= q_t(1-.082)$	$= .92\,q_t$
2	$q_t\beta(1-\gamma)/2$	$= q_t(.082)(1-.16)/2$	$= .034\,q_t$
3	$q_t\beta\gamma$	$= q_t(.082)(.16)$	$= .013\,q_t$

2 Sums 2 component

$n(2,a) = n(5,a) + n(4,a) + n(3,a) + n(2,a) = 1+1+1+29 = 32$
$n(2,p) = n(3,p) + n(4,p) + n(3,p) + n(2,p) = 1+5+2+10 = 18$
} $n(3,a)+n(3,p)$ are assumed to be equal to the sum of higher n's

$sum(2) = 2[n(2,a) + .1\,n(2,p)] = 2[32 + .1(18)] = 67.6$
$sum(1) = sum(2) + n(1,a) + .1\,n(1,p) = 67.6 + 12 + .1(0) = 79.6$

3. MGL 2 Component

$\beta = [sum(2) + .5]/[sum(1) + n(5,a) + .1\,n(5,p) + 1] = [67.6 + .5]/[79.6 + 788 + (.1)(49) + 1] = .078$

4 Probabilities

# Comp	Eq for Q_k	
1	$q_t(1-\beta)$	$= .92\,q_t$
2	$q_t\beta$	$= .078\,q_t$

ATTACHMENT 2:

EXCERPT FROM RESIDUAL HEAT REMOVAL SYSTEM COMMON CAUSE FAILURE CALCULATIONS

CALCULATIONAL FORM
NUCLEAR ANALYSIS DEPARTMENT
FORM 17-3810(10-82)

NSP Northern States Power Company

SUBJECT RHR CC SHEET NO 1 OF 5

PREPARED BY CKB DATE 12/3/91 VERIFIED BY _____ DATE _____

Objective

This file contains the common cause calculation for RHR.

The common cause is summarized in folder II.SMN.91.007

Calculation

This calculation uses the common cause (Section 6) part of the procedure in section 4 of Calculation file II.SMN.91.008 with some changes to ensure nonzero probabilities.

The following shows the formulas used:

1. Determine n(K,a), n(K,p), n(S,a) and n(S,p)

This is done by reviewing industry data and determining each value.

n(K,a) ≡ The number of actual failures involving K components
n(K,p) ≡ " " " potential " " " "
n(S,a) ≡ " " " actual single Common Cause failures
n(S,p) ≡ " " " potential " " " "

It should be noted that n(1,a) + n(S,a), and n(1,p) & n(S,p) are treated the same in the analysis.

2. Calculate Sum(K)

$$Sum(K) = K[n(K,a) + .1n(K,p)] + [K+1][n(K+1,a) + .1n(K+1,p)] + \cdots + m[n(m,a) + .1n(m,p)]$$

m ≡ Common Cause group population
K ≡ number of components within population m $K \le m$

For 6 component common cause:

$$sum(6) = 6[n(6,a) + .1n(6,p)]$$
$$sum(5) = Sum(6) + 5[n(5,a) + .1n(5,p)]$$
$$sum(4) = Sum(5) + 4[n(4,a) + .1n(4,p)]$$
$$Sum(3) = Sum(4) + 3[n(3,a) + .1n(3,p)]$$
$$Sum(2) = Sum(3) + 2[n(2,a) + .1n(2,p)]$$
$$sum(1) = Sum(2) + n(1,a) + .1n(1,p)$$

CALCULATIONAL FORM
NUCLEAR ANALYSIS DEPARTMENT
FORM 17-3810(10-82)

NSP Northern States Power Company

SUBJECT _____ SHEET NO 2 OF 5

PREPARED BY CJB DATE 12/3/91 VERIFIED BY _____ DATE _____

3 Calculate MGL Factors

$\beta = [\,sum(2) + .5\,] \,/\, [\,sum(1) + n(s,a) + .1n(s,p)\,]$
$\gamma = [\,sum(3) + .5\,] \,/\, [\,sum(2) + 1\,]$
$\delta = [\,sum(4) + .5\,] \,/\, [\,sum(3) + 1\,]$
$\epsilon = [\,sum(5) + .5\,] \,/\, [\,sum(4) + 1\,]$
$\zeta = [\,sum(6) + .5\,] \,/\, [\,sum(5) + 1\,]$
$\eta = 1$

The above example is for a 6 component system. These equations are not the same as the referenced equations because the referenced equations will result in zero probabilities for some common cause basic events. The above change is to add .5 to sum(K) in the numerator an 1.0 to sum(K) in the denominator to account for the fact that the data is limited. See folder II.SMN.91.008 section 3 calculation for a more detailed explination of the change to the equations in section 4 of that folder.

4. Common Cause Probabilities

The base equation is:

$$Q_K = \frac{1}{\binom{m-1}{K-1}} \left(\prod_{i=1}^{K} \rho_i \right) (1 - \rho_{K+1})\, Q_t$$

Reference: NUREG/CR-4780 page 3-19 Table 3-1

$Q_K \equiv$ probability of a basic event involving K specific components $1 \le K \le m$
$Q_t \equiv$ is the total failure probability of component $A = \sum_{K=1}^{m} \binom{m-1}{K-1} Q_K$
$\binom{m-1}{K-1} \equiv [(m-1)!] \,/\, [(m-K)!\,(K-1)!]$
$K \equiv$ number of components within population m $K \le m$
$m =$ total number of components in the common cause group
$\rho_1 = 1,\ \rho_2 = \beta,\ \rho_3 = \gamma, \ldots, \rho_{m+1} = 0$

For an 8 component common cause:

# Comp	Eq
1	$Q_t(1-\beta)$
2	$Q_t\beta(1-\gamma)/7$
3	$Q_t\beta\gamma(1-\delta)/21$
4	$Q_t\beta\gamma\delta(1-\epsilon)/35$
5	$Q_t\beta\gamma\delta\epsilon(1-\zeta)/35$
6	$Q_t\beta\gamma\delta\epsilon\zeta(1-\eta)/21$
7	$Q_t\beta\gamma\delta\epsilon\zeta\eta(1-\theta)/7$
8	$Q_t\beta\gamma\delta\epsilon\zeta\eta\theta$

This folder will calculate the factor which is multiplied to Q_t for each component.

CALCULATIONAL FORM
NUCLEAR ANALYSIS DEPARTMEN
FORM 17-3810(10-82)

NSP Northern States Power Company

SUBJECT _____ SHEET NO 3 OF 5

PREPARED BY CTB DATE 12/3/91 VERIFIED BY _____ DATE _____

For ease of use the $\binom{m-1}{k-1}$ factor will be determined for different m and k values.

m	k	(m-1)! / [(m-k)!(k-1)!]		
2	1	(2-1)! / [(2-1)!(1-1)!] = 1/(1*1) = 1		2 components
"	2	(2-1)! / [(2-2)!(2-1)!] = 1/(1*1) = 1		
3	1	(3-1)! / [(3-1)!(1-1)!] = 2/(2*1) = 1		3 components
"	2	(3-1)! / [(3-2)!(2-1)!] = 2/(1*1) = 2		
"	3	(3-1)! / [(3-3)!(3-1)!] = 2/(1*2) = 1		
4	1	(4-1)! / [(4-1)!(1-1)!] = 6/(6*1) = 1		4 components
"	2	(4-1)! / [(4-2)!(2-1)!] = 6/(2*1) = 3		
"	3	(4-1)! / [(4-3)!(3-1)!] = 6/(1*2) = 3		
"	4	(4-1)! / [(4-4)!(4-1)!] = 6/(1*6) = 1		
6	1	(6-1)! / [(6-1)!(1-1)!] = 120/(120*1) = 1		6 components
"	2	(6-1)! / [(6-2)!(2-1)!] = 120/(24*1) = 5		
"	3	(6-1)! / [(6-3)!(3-1)!] = 120/(6*2) = 10		
"	4	(6-1)! / [(6-4)!(4-1)!] = 120/(2*6) = 10		
"	5	(6-1)! / [(6-5)!(5-1)!] = 120/(1*24) = 5		
"	6	(6-1)! / [(6-6)!(6-1)!] = 120/(1*120) = 1		
8	1	(8-1)! / [(8-1)!(1-1)!] = 5040/(5040*1) = 1		8 component
"	2	(8-1)! / [(8-2)!(2-1)!] = 5040/(720*1) = 7		
"	3	(8-1)! / [(8-3)!(3-1)!] = 5040/(120*2) = 21		
"	4	(8-1)! / [(8-4)!(4-1)!] = 5040/(24*6) = 35		
"	5	(8-1)! / [(8-5)!(5-1)!] = 5040/(6*24) = 35		
"	6	(8-1)! / [(8-6)!(6-1)!] = 5040/(2*120) = 21		
"	7	(8-1)! / [(8-7)!(7-1)!] = 5040/(1*720) = 7		
"	8	(8-1)! / [(8-8)!(8-1)!] = 5040/(1*5040) = 1		

(1-1)! = 0! = 1
(2-1)! = 1! = 1
(3-1)! = 2! = 2
(4-1)! = 3! = 6
(5-1)! = 4! = 24
(6-1)! = 5! = 120
(7-1)! = 6! = 720
(8-1)! = 7! = 5,040

CALCULATIONAL FORM
NUCLEAR ANALYSIS DEPARTMENT
FORM 17-3810(10-82)

Northern States Power Company

SUBJECT _____ SHEET NO 4 OF 5

PREPARED BY CAB DATE 12/3/91 VERIFIED BY _____ DATE _____

1. Determine n values

Plant	Date	Actual Failures	Potential Failures	Source	
Arkansas 1-2	1978	0	2	EPRI NP-3967 Table 3-22 Sheet 2 of 6	FTR
Millstone 2	3/79	2	0	" " " " 3 "	FTR
Monticello	12/72	1	3	" " " " 4 "	FTR
Browns Ferry 1	9/74	2	0	" " " " 5 "	FTR
Brunswick 2	4/79	2	0	" " " 5 "	FTS

FTS $n(s,a) = FS = 34$ $n(s,p) = PFS = 3$
FTR $n(s,a) = FR + F = 28 + 2 = 30$ $n(s,p) = PF + PFR = 3 + 6 = 9$

Source for $n(s,a)$ + $n(s,p)$ is EPRI NP-3967 Table 3-21 Linear Event Category

FTS $n(3,a) = 1$ $n(1,a) = 0$ $n(s,a) = 34$
$n(2,p) = 0$ $n(1,p) = 0$ $n(s,p) = 3$

FTR $n(3,a) = 0$ $n(2,a) = 2$ $n(1,a) = 1$ $n(s,a) = 30$
$n(3,p) = 1$ $n(2,p) = 1$ $n(1,p) = 0$ $n(s,p) = 9$

Note: The NUREG/CR-2098 was not used because of potential duplication of failures with the EPRI report.

2. Sums - RHR 4 component FTS

$sum(4) = 4[n(4,a) + .1n(4,p)] = 4[0 + .1(0)] = 0$
$sum(3) = sum(4) + 3[n(3,a) + .1n(3,p)] = 0 + 3[0 + .1(0)] = 0$
$sum(2) = sum(3) + 2[n(2,a) + .1n(2,p)] = 0 + 2[1 + .1(0)] = 2$
$sum(1) = sum(2) + n(1,a) + .1n(1,p) = 2 + 0 + .1(0) = 2$

3. MGL's RHR 4 Component FTS

$\delta = [sum(4) + .5]/[sum(3) + 1] = [0 + .5]/[0 + 1] = .5$
$\gamma = [sum(3) + .5]/[sum(2) + 1] = [0 + .5]/[2 + 1] = .17$
$\beta = [sum(2) + .5]/[sum(1) + n(s,a) + .1n(s,p)] = [2 + .5]/[2 + 34 + .1(3) + 1] = .067$

4 Probabilities - RHR 4 component FTS

# Comp	Eq		
1	$q_t(1-\beta)$	$= q_t(1-.067)$	$= .93\ q_t$
2	$q_t\beta(1-\gamma)/3$	$= q_t(.067)(1-.17)/3$	$= .019\ q_t$
3	$q_t\beta\gamma(1-\delta)/3$	$= q_t(.067)(.17)(1-.5)/3$	$= .0019\ q_t$
4	$q_t\beta\gamma\delta$	$= q_t(.067)(.17)(.5)$	$= .0057\ q_t$

CALCULATIONAL FORM
NUCLEAR ANALYSIS DEPARTMENT
FORM 17-3810(10-82)

Northern States Power Company

SUBJECT _____ SHEET NO 5 OF 5

PREPARED BY LHB DATE 12/3/91 VERIFIED BY _____ DATE _____

2. Sums - RHR 4 component FTR

$Sum(4) = 4[n(4,a) + .1\,n(4,p)] = 4[0 + .1(0)] = 0$
$Sum(3) = sum(4) + 3[n(3,a) + .1\,n(3,p)] = 0 + 3[0 + .1(1)] = .3$
$Sum(2) = Sum(3) + 2[n(2,a) + .1\,n(2,p)] = .3 + 2[2 + .1(1)] = 4.5$
$Sum(1) = sum(2) + n(1,a) + .1\,n(1,p) = 4.5 + 1 + .1(0) = 5.5$

3. MGL's - RHR 4 component FTR

$\delta = [sum(4) + .5] / [sum(3) + 1] = [0 + .5]/[.3 + 1] = .38$
$\gamma = [sum(3) + .5] / [sum(2) + 1] = [.3 + .5]/[4.5 + 1] = .15$
$\beta = [sum(2) + .5]/[sum(1) + n(s,a) + .1\,n(s,p) + 1] = [4.5 + .5]/[5.5 + 30 + .1(9) + 1] = .13$

4 Probabilities - RHR 4 component FTR

# Comp	Eq		
1	$q_t(1-\beta)$	$= q_t(1-.13)$	$= .87\,q_t$
2	$q_t\beta(1-\gamma)/3$	$= q_t(.13)(1-.15)/3$	$= .037\,q_t$
3	$q_t\beta\gamma(1-\delta)/3$	$= q_t(.13)(.15)(1-.38)/3$	$= .0040\,q_t$
4	$q_t\beta\gamma\delta$	$= q_t(.13)(.15)(.38)$	$= .0074\,q_t$

2 Sums RHR 2 component FTR

$n(2,p) = n(3,p) + n(2,p) = 1 + 1 = 2$ add higher orders of n

$Sum(2) = 2[n(2,a) + .1\,n(2,p)] = 2[2 + .1(1)] = 4.2$
$Sum(1) = sum(2) + n(1,a) + .1\,n(1,p) = 4.2 + 1 + .1(0) = 5.2$

3. MGL RHR 2 component FTR

$\beta = [Sum(2) + .5]/[sum(1) + n(s,a) + .1\,n(s,p) + 1] = [4.2 + .5]/[5.2 + 30 + .1(9) + 1] = .13$

4 Probabilities

# Comp	Eq		
1	$q_t(1-\beta)$	$= q_t(1-.13)$	$= .87\,q_t$
2	$q_t\beta$	$\approx q_t .13$	$= .13\,q_t$