UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
612 EAST LAMAR BLVD, SUITE 400
ARLINGTON, TEXAS 76011-4125

June 13, 2008

EA 07-204

Stewart B. Minahan
Vice President-Nuclear and CNO
Nebraska Public Power District
P.O. Box 98
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SUBJECT: FINAL SIGNIFICANCE DETERMINATION FOR A WHITE FINDING AND NOTICE OF VIOLATION, NRC INSPECTION REPORT 05000298/2008008, COOPER NUCLEAR STATION

Dear Mr. Minahan:

The purpose of this letter is to provide you the final results of our significance determination of the preliminary Greater than Green finding identified in the Nuclear Regulatory Commission (NRC) Inspection Report 05000298/2008007. The inspection finding was assessed using the significance determination process and was preliminarily characterized as a finding of greater than very low safety significance resulting in the need for further evaluation to determine the significance and, therefore, the need for additional NRC action.

Our preliminary finding was discussed with your staff during an exit meeting on March 18, 2008. The finding involved two procedures used by operators to bring the plant to a safe shutdown condition in the event of certain postulated fire scenarios. The procedures could not be performed as written. This performance deficiency involved the failure to properly verify and validate these infrequently used procedures.

The NRC's preliminary assessment of the safety significance of this inspection finding was a modified bounding analysis based upon the best available information. This simplified analysis demonstrated that this finding did not have high importance to safety, but that additional information and analyses would be needed to determine the final significance. Therefore, the finding was issued with a preliminary safety significance of Greater than Green.

At the request of Nebraska Public Power District, a regulatory conference was held on May 13, 2008, to further discuss your views on this issue. A copy of the handout you provided is attached to the regulatory conference meeting summary (ML081550102). During the regulatory conference, your staff described your assessment of the significance of the finding and your views on the applicability of the Interim Enforcement Discretion Policy.

After considering the information developed during this inspection, the additional information you provided in your letter dated May 8, 2008 (ML081540362), and the information your staff provided at the regulatory conference, the NRC has concluded that the inspection finding is appropriately characterized as White, an issue with low to moderate increased importance to safety, which may require additional NRC inspections.

The final significance determination, described in Enclosure 2, was based on the significance determination process Phase 3 analysis performed by the NRC staff using multiple risk tools including, a standardized plant analysis risk model simulation of the potential fires that would impact this finding, hand calculations, and a linked event tree model of the Cooper Nuclear Station's remote shutdown capabilities developed by NRC analysts. This evaluation considered insights and values provided by your staff. The results of your analyses and fire modeling provided important information needed for our staff to complete our significance determination process evaluation. Our final assessment of the change in risk due to this performance deficiency has dropped an order of magnitude. For fire areas that would not have the potential to cause a control room evacuation, the NRC results closely match your results. However, for cases with the potential to cause control room evacuation, which dominated the safety impact, our results indicated greater safety significance than your results. The areas where the two analyses differed significantly included the frequency with which operators would abandon the main control room, and the assessment of the human reliability associated with the expected recovery actions. Your analysis did not adequately model the impact of spurious operations due to fire damage in alternate shutdown fire areas or treat them consistent with the plant operating procedure, which would be expected to result in a higher evacuation frequency. In addition, your evaluation did not include core damage sequences that involved the failure of the high pressure coolant injection system early in the event. These sequences represented about one fourth of the risk in our evaluation. We estimated the change in core damage frequency associated with this finding to be 8.1×10^{-6}, as discussed in Enclosure 2 to this letter, compared to your final significance of 8.6×10^{-8}.

You have 30 calendar days from the date of this letter to appeal the staff's determination of significance for the identified White finding. Such appeals will be considered to have merit only if they meet the criteria given in NRC Inspection Manual Chapter 0609, “Significance Determination Process,” Attachment 2, “Process for Appealing NRC Characterization of Inspection Findings (Significance Determination Process Appeal Process).”

The NRC has also determined that the two examples of inadequate fire response operating procedures involved a violation of NRC requirements as cited in the enclosed Notice of Violation (Notice). The circumstances surrounding the violation are described in detail in NRC Inspection Report 05000298/2008007. This violation of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings” involved steps contained in Emergency Procedures 5.4POST-FIRE, “Post-Fire Operational Information,” and 5.4FIRE-S/D, “Fire Induced Shutdown From Outside Control Room.” Certain steps in the procedures intended to reposition motor-operated valves locally, would not have worked as written because the steps were not appropriate for the configuration of the motor-starter circuits. As a consequence of this violation, these quality-related procedures would have challenged the operators' ability to bring the plant to a safe shutdown condition in the event of certain fires. In accordance with the NRC Enforcement Policy, the Notice is considered escalated enforcement action because it is associated with a White finding.

Because plant performance for this issue has been determined to be in the regulatory response band, we will use the NRC Action Matrix, as described in NRC Inspection Manual Chapter 0305, “Operating Reactor Assessment Program,” to determine the most appropriate NRC response and any increase in NRC oversight. We will notify you by separate correspondence of that determination.

The staff has reviewed the position provided in your March 10, 2008, letter (ML080740507) concerning the circumstances surrounding this violation and how the Interim Enforcement Policy Regarding Enforcement Discretion for Certain Fire Protection Issues related to this violation. During the regulatory conference, your presentation reiterated the position stated in your letter. Our review has concluded that your letter and regulatory conference presentation provided no new information. Therefore, we maintain that all of the requirements of the Interim Enforcement Policy Regarding Enforcement Discretion for Certain Fire Protection Issues were not satisfied and enforcement discretion will not be granted for this violation.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure(s), and your response, if you choose to provide one, will be made available electronically for public inspection in the NRC Public Document Room or from the NRC’s document system (ADAMS), accessible from the NRC website at www.nrc.gov/reading-rm/pdr.html or www.nrc.gov/reading-rm/adams.html. To the extent possible, your response should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the Public without redaction.

Sincerely,

/RA/

Roy J. Caniano, Director
Division of Reactor Safety

Docket: 50-298
License: DPR-46

Enclosures:
1. Notice of Violation
2. Final Significance Determination
3. Supplemental Information

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SUNSI Review Completed: **LJS** ADAMS: ☒ **Yes** ☐ No **Initials:** __________
☒ **Publicly Available** ☐ Non-Publicly Available ☐ Sensitive ☒ **Non-Sensitive**
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SRI/EB2	SRI/EB2	C:DRS/EB2	SRA/DRS	ACES	C:DRP/C	D:DRS
JMMateychick	NFO'Keefe	LJSmith	DLoveless	CMaier	DChamberlain	RJCaniano
E /RA/	***/RA/***	***/RA/***	***/RA/***	***/RA/***	***/RA/***	***/RA/***
6/7/08	6/5/08	6/5/08	6/5/08	6/5/08	6/5/08	6/13/08

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NOTICE OF VIOLATION

Nebraska Public Power District
Cooper Nuclear Station

Docket No. 50-298
License No. DPR-46
EA-07-204

During an NRC inspection completed on March 18, 2008, a violation of NRC requirements was identified. In accordance with the NRC Enforcement policy, the violation is listed below:

> Appendix B to 10 CFR Part 50, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings.
>
> Procedure 0.4A, "Procedure Change Process Supplement," Revision 0, implements measures to ensure the procedure quality required by Criterion V for procedures designated as quality-related. Attachment 2 to this procedure requires verification and validation to be performed periodically, when writing a new procedure, when significant changes are made to sequencing of complex steps in existing procedures, and when infrequently used procedures are written or changed. Verification and validation efforts are defined in this procedure as actions to confirm that the procedure steps: (1) are usable; (2) are accurate; (3) contain the appropriate level of detail; (3) use equipment nomenclature that corresponds to the actual hardware; and (4) satisfy plant design and licensing basis. Procedure 0.4A applies to changes to Emergency Procedures 5.4POST-FIRE and 5.4FIRE-S/D.
>
> Contrary to the above, between 1997 and June, 2007, the licensee failed to ensure that two emergency operating procedures which controlled activities affecting quality were appropriate to the circumstances. Specifically, the licensee changed Emergency Procedures 5.4POST-FIRE and 5.4FIRE-S/D in 1997 to add steps that were inappropriate to the circumstances because they would not work as written. Additionally, the licensee failed to properly verify and validate procedure steps to ensure that they would work to accomplish the necessary actions.

This violation is associated with a White significance determination process finding.

The NRC has concluded that information regarding the reason for the violation, the corrective actions taken and planned to correct the violation and prevent recurrence and the date when full compliance was achieved is already adequately addressed on the docket in NRC Inspection Reports 05000298/2007008, 05000298/2008007, and Licensee Event Report 05000298/2007005-00. However, you are required to submit a written statement or explanation pursuant to 10 CFR 2.201 if the description therein does not accurately reflect your corrective actions or your position. In that case, or if you choose to respond, clearly mark your response as a "Reply to a Notice of Violation," include the EA number, and send it to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001 with a copy to the Regional Administrator, Region IV, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice).

If you choose to respond, your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC website at www.nrc.gov/reading-rm/pdr.html or www.nrc.gov/reading-rm/adams.html. Therefore, to the extent possible, the response should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the Public without redaction.

If you contest this enforcement action, you should also provide a copy of your response, with the basis of your denial, to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

Dated this 13th day of June 2008

FINAL SIGNIFICANCE DETERMINATION SUMMARY

Significance Determination Basis

a. Phase 1 Screening Logic, Results, and Assumptions

In accordance with NRC Inspection Manual Chapter 0612, Appendix B, "Issue Screening," the issue was determined to be more than minor because it was associated with the equipment performance attribute and affected the mitigating systems cornerstone objective to ensure the availability, reliability, or function of a system or train in a mitigating system in that 10 motor-operated valves would not have functioned following a postulated fire in multiple fire zones. The following summarizes the valves and fire areas affected:

Valves Affected

HPCI-MO-14	Steam Supply to High Pressure Coolant Injection (HPCI) Turbine Valve
HPCI-MO-16	Steam Supply to HPCI Turbine Outboard Isolation Valve
RHR-MO-17	Shutdown Cooling Suction Valve
RHR-MO-25A	Residual Heat Removal (RHR) A Inboard Injection Valve
RHR-MO-25B	RHR B Inboard Injection Valve
RHR-MO-67	RHR Discharge to Radwaste Inboard Valve
RHR-MO-921	Augmented Offgas Steam Supply Valve
RWCU-MO-18	Outboard Reactor Water Cleanup Isolation Valve
MS-MO-77	Outboard Main Steam Drain Line Isolation Valve
RR-MO-53A	Reactor Recirculation Pump A Discharge Valve

Fire Areas Affected

CB-A	Control Building Reactor Protection System Room 1A, Seal Water Pump Area, and Hallway
CB-A-1	Control Building Division 1 Switchgear Room and Battery Room
CB-B	Control Building Division 2 Switchgear Room and Battery Room
CB-C	Control Building Reactor Protection System Room 1B
CB-D	Control Room, Cable Spreading Room, Cable Expansion Room, and Auxiliary Relay Room
RB-CF	Reactor Building North/Northwest 903, Northwest Quad 889 and 859, and RHR Heat Exchanger Room A
RB-DI (SW)	Reactor Building South/Southwest 903, Southwest Quad 889 and 859, and RHR Heat Exchanger Room B
RB-DI (SE)	Reactor Building RHR Pump B/HPCI Pump Room
RB-J	Reactor Building Critical Switchgear Room 1F
RB-K	Reactor Building Critical Switchgear Room 1G
RB-M	Reactor Building North/Northwest 931 and RHR Heat Exchanger Room A

RB-N	Reactor Building South/Southwest 931 and RHR Heat Exchanger Room B
RB-FN	Reactor Building 903, Northeast Corner
TB-A	Turbine Building (multiple areas)

The significance determination process (SDP) Phase 1 Screening Worksheet (Manual Chapter 0609, Attachment 4), Table 3b directs the user to Manual Chapter 0609, Appendix F, "Fire Protection Significance Determination Process," because it affected fire protection defense-in-depth strategies involving post fire safe shutdown systems. However, Manual Chapter 0308, Attachment 3, Appendix F, "Technical Basis for Fire Protection Significance Determination Process for at Power Operations," states that Manual Chapter 0609, Appendix F, does not include explicit treatment of fires in the main control room. The Phase 2 process can be utilized in the treatment of main control room fires, but it is recommended that additional guidance be sought in the conduct of such an analysis.

b. Phase 2 Risk Estimation

Based on the complexity and scope of the subject finding and the significance of the finding to main control room fires, the analyst determined that a Phase 2 estimation was not appropriate.

c. Phase 3 Analysis

In accordance with Manual Chapter 0609, Appendix A, the analyst performed a Phase 3 analysis using input from the Nebraska Public Power District, "Individual Plant Examination for External Events (IPEEE) Report – 10 CFR 50.54(f) Cooper Nuclear Station, NRC Docket No. 50-298, License No. DPR-46," dated October 30, 1996, the Standardized Plant Analysis Risk (SPAR) Model for Cooper, Revision 3.31, dated September 2007, licensee input (see documents reviewed list in Enclosure 3), a probabilistic risk assessment using a linked event tree model created by the analyst for evaluating main control room evacuation scenarios, and appropriate hand calculations.

<u>Assumptions</u>:

Following the regulatory conference, the analysts revised the Phase 3 analysis. To evaluate the change in risk caused by this performance deficiency, the analyst made the following assumptions:

1. For fire zones that do not have the possibility for a fire to require the main control room to be abandoned, the ignition frequency identified in the IPEEE is an appropriate value.

2. The fire ignition frequency for the main control room (P_{FIF}) is best quantified by the licensee's revised value of 6.88×10^{-3}/yr.

3. Of the original 64 fire scenarios evaluated, 18 were determined to be redundant and were eliminated, 41 of the remaining (documented in Table 1)

were identified as the predominant sequences associated with fires that did not result in control room abandonment.

4. The baseline conditional core damage probability for a control room evacuation at the Cooper Nuclear Station is best represented by the creation of a new probabilistic risk assessment tool created by the analyst using a linked event tree method. The primary event tree used in this model is displayed as Figure 1 in the Attachment. The baseline conditional core damage probability as calculated by the linked event tree model was 1.14×10^{-1}, which is similar to the generic industry value of 0.1.

5. The analyst used an event tree, RECOVERY-PATH, shown in Figure 2 in the Attachment, to evaluate the likelihood of operator recovery via either restoration of HPCI or manually opening Valve RHR-MO-25B. The resulting non-recovery probability was 7.9×10^{-2}.

6. The risk related to a failure of Valve RHR-MO-25B to open following an evacuation of the main control room was evaluated using the analyst's linked event tree model. The conditional core damage probability calculated by the linked event tree model was 2.4×10^{-1}.

7. Any fire in the main control room that is large enough to grow and that goes unsuppressed for 20 minutes will lead to a control room evacuation.

8. Any fire that is unsuppressed by automatic or manual means in the auxiliary relay room, the cable spreading room, the cable expansion room or Area RB-FN will result in a main control room evacuation.

9. The Cooper SPAR model, Revision 3.31, represents an appropriate tool for evaluation of the core damage probabilities associated with postulated fires that do not result in main control room evacuation.

10. All postulated fires in this analysis resulted in a reactor scram. In addition, the postulated fire in Fire Area RB-K resulted in a loss-of-offsite power.

11. Valves RHR-MO-25A and RHR-MO-25B are low pressure coolant injection system isolation valves. These valves can prevent one method of decay heat removal in the shutdown cooling mode of operation.

12. For Valves RHR-MO-25A and RHR-MO-25B, the subject performance deficiency only applies to the portion of the post fire procedures that direct the transition into shutdown cooling. Therefore, the low pressure injection function is not affected.

13. Valve RHR-MO-25B must open from the motor-control center for operators to initiate alternate shutdown cooling from the alternate shutdown panel following a main control room evacuation.

14. Valve RHR-MO-17 is one of two RHR system shutdown cooling cold-leg suction isolation valves. These valves can prevent decay heat removal in the shutdown cooling mode of operation.

15. Valve RWCU-MO-18 is the outboard isolation valve for the reactor water cleanup system. The system is a closed-loop system outside containment with piping rated at 1250 psig and 575°F. The isolation of this system is designed to protect the system demineralizer resins and as an isolation for a piping break outside containment. The success or failure of the resins will not affect the likelihood of core damage. The failure of the system piping without isolation would contribute to an intersystem loss-of-coolant accident. However, the likelihood that the system piping fails and an automatic isolation is not generated would be very low.

16. Valve MS-MO-77 is a 3-inch main steam line drain. The valve isolates a high pressure drain line heading back to the main condenser. The licensee stated that the failure to isolate this line would not result in a high enough loss-of-reactor coolant to affect the core damage frequency. However, the failure to close this valve could result in a transient that would not have otherwise been caused by the postulated fire scenario.

17. Valve RR-MO-53A is the discharge isolation valve for Reactor Recirculation Pump 1-A. The failure to close either this valve or Valve RR-MO-43A would result in a short circuit of the shutdown cooling flow to the reactor vessel. The performance deficiency did not apply to Valve RR-MO-43A.

18. Valve RHR-MO-921 provides isolation of a 3-inch steam line heading to the augmented offgas system. Just downstream of the valve the piping reduces to a 1-inch diameter line. This line taps off the HPCI pump steam line and terminates in the main condenser high pressure drain header. Because this is a 1-inch line, the valve does not contribute to the large-early release frequency except for postulated seismic events. Additionally, inventory losses would be minimal and not affect mitigating systems necessary following the subject fire initiation. Finally, the line would be automatically isolated upon the isolation of the HPCI pump steam line. However, the failure to close this valve could result in a transient that would not have otherwise been caused by the postulated fire scenario.

19. Valve HPCI-MO-14 provides isolation of the HPCI system from the reactor coolant system. The failure to isolate this valve, when required, would result in reactor vessel level increasing in an uncontrolled manner, filling the steam lines and suppressing the steam to all steam-driven equipment. This increases the core damage probability because it results in the loss of all high pressure systems.

20. Valve HPCI-MO-16 provides isolation of the HPCI system from the reactor coolant system. The failure to isolate this valve, when required, would result in reactor vessel level increasing in an uncontrolled manner, filling the steam

lines and suppressing the steam to all steam-driven equipment. This increases the core damage probability because it results in the loss of all high pressure systems.

21. Valve RHR-MO-67 provides isolation of the RHR system from radwaste. Post-fire instructions affecting this valve are to assist in placing shutdown cooling in service. Failure of this valve would delay placing shutdown cooling in service and act as a distraction to operators placing the plant in a safe shutdown condition.

22. The exposure time used for evaluating this finding should be determined in accordance with Inspection Manual Chapter 0609, Appendix A, Attachment 2, “Site Specific Risk-Informed Inspection Notebook Usage Rules.” Given that the performance deficiency was known to have existed for many years, the analyst used the 1-year of the current assessment cycle as the exposure period.

23. Based on fire damage and/or procedures, equipment affected by a postulated fire in a given fire zone is unavailable for use as safe shutdown equipment.

24. The performance deficiency would have resulted in each of the demanded valves failing to respond following a postulated fire.

25. In accordance with the requirements of Procedure 5.4POST-FIRE, operators would perform the post-fire actions directed by the procedure following a fire in an applicable fire zone. Therefore, the size and duration of the fire would not be relevant to the failures caused by the performance deficiency.

26. Given Assumption 25, severity factors and probabilities of non-suppression were not addressed for postulated fires that did not result in main control room evacuation.

<u>Postulated Fires Not Involving Main Control Room Evacuation</u>:

The senior reactor analyst used the SPAR model for Cooper Nuclear Station to estimate the change in risk, associated with fires in each of the associated fire scenarios (Table 1, Items 1 – 41) that was caused by the finding. Average unavailability for test and maintenance of modeled equipment was assumed, and a cutset truncation of 1.0×10^{-13} was used. For each fire zone, the analyst calculated a baseline conditional core damage probability consistent with Assumptions 9, 10, 25 and 26.

For areas where the postulated fire resulted in a reactor scram, the frequency of the transient initiator, IE-TRANS, was set to 1.0. All other initiators were set to the house event “FALSE,” indicating that these events would not occur at the same time as a reactor scram. Likewise, for Fire Area RB-K, the frequency of the loss-of-offsite power initiator, IE-LOOP, was set to 1.0 while other initiators were set to the house event “FALSE.”

With input from the detailed IPEEE notebooks, maintained by the licensee, the analyst was able to better assess the fire damage in each zone. This resulted in a more realistic evaluation of the baseline fire risk for the zone, and lowering the change in risk for each example.

Consistent with guidance in the Reactor Accident Sequence Precursor Handbook, including NRC document, "Common-Cause Failure Analysis in Event Assessment, (June 2007)," the baseline established for the fire zone, and Assumptions 22 through 26, the analyst modeled the resulting condition following a postulated fire in each fire zone by adjusting the appropriate basic events in the SPAR model. Both the baseline and conditional values for each fire zone are documented in Table 1.

As shown in Table 1, the analyst calculated a change in core damage frequency (ΔCDF) associated with these 41 fire scenarios of 2.9×10^{-6}/yr.

The analyst evaluated the licensee’s qualitative reviews of the 13 fire scenarios that were impacted by the failure of the HPCI turbine to trip. In these scenarios, HPCI floods the steam lines and prevents further injection by either HPCI or reactor core isolation cooling system. Qualitatively, not all fires will grow to a size that causes a loss of the trip function due to spatial separation. Additionally, not all unsuppressed fires would cause a failure of the HPCI trip function. Finally, no operator recovery was credited in these evaluations.

Given that these qualitative factors would all tend to decrease the significance of the finding, the analyst believed that the total change in risk would be significantly lower than the 2.9×10^{-6}/yr documented above. Based on analyst judgment and an assessment of the evidence provided by the licensee, an occurrence factor of 0.1 was applied to the13 fire scenarios. This resulted in a total ΔCDF of 7.8×10^{-7}/yr. Therefore, the analyst determined that this value was the best estimate of the safety significance for these 41 fire scenarios.

Table 1
Postulated Fires Not Involving Main Control Room Evacuation

Fire Area/ Shutdown Strategy	Area/ Zone	Scenario Number	Scenario Description	Ignition Frequency	Base CCDP	Case CCDP	Estimated delta-CDF Contribution	Function Affected
RB-CF	1C	1	RHR A Pump Room	2.94E-03	8.82E-07	8.15E-05	2.37E-07	Shut HPCI-MO-14, HPCI-MO-16, RHR-MO-921, RWCU-MO-18 and MS-MO-77
	2A/2C	2	MCC K	3.02E-03	2.76E-05	1.28E-04	3.03E-07	
		3	MCC Q	3.93E-03	2.76E-05	1.28E-04	3.95E-07	
		4	MCC R	3.43E-03	2.76E-05	1.28E-04	3.44E-07	
		5	MCC RB	1.62E-03	1.12E-03	1.21E-03	1.46E-07	
		6	MCC S	2.23E-03	1.12E-03	1.21E-03	2.01E-07	
		7	MCC Y	3.83E-03	1.12E-03	1.21E-03	3.45E-07	
		8	Panel AA3	9.98E-04	2.76E-05	1.28E-04	1.00E-07	
		9	Panel BB3	9.98E-04	1.12E-03	1.21E-03	8.98E-08	
		10	RCIC Starter Rack	1.32E-03	5.27E-06	8.27E-05	1.02E-07	
		11	250V Div 1 Rack	5.10E-04	2.76E-05	1.28E-04	5.12E-08	
		12	250V Div 2 Rack	2.09E-04	1.12E-03	1.21E-03	1.88E-08	
		13	ASD Panels	3.02E-04	1.12E-03	1.21E-03	2.72E-08	
CB-A	7A	14		6.74E-03	7.64E-04	7.64E-04	0.00E+00	Open RHR-MO-25B and RHR-MO-67
	7B	15		1.36E-03	2.61E-06	2.61E-06	0.00E+00	
	8C	16	RPS Room 1A	4.15E-03	1.75E-07	1.75E-07	0.00E+00	
	8D	17		2.42E-03	3.57E-04	3.58E-04	4.84E-10	
	10B	18	Hallway (used CB corridor)	1.09E-02	2.05E-05	2.85E-05	8.74E-08	

CB-A-1	8H	19	DC Switchgear Room 1A	4.27E-03	3.49E-04	3.49E-04	1.28E-09	Open RHR-MO-17, RHR-MO-25B, and RHR-MO-67
	8E	20	Battery Room 1A	2.25E-03	8.74E-06	1.03E-05	3.51E-09	
CB-B	8G	21	DC Switchgear Room 1B	4.27E-03	1.82E-03	1.83E-03	3.42E-08	Open RHR-MO-25A
	8F	22	Battery Room 1B	2.25E-03	4.81E-06	5.73E-06	2.07E-09	
CB-C	8B	23	RPS Room 1A	4.15E-03	1.75E-07	1.77E-07	5.81E-12	Open RHR-MO-17, RHR-MO-25A, and RHR-MO-67
	8C	24		4.15E-03	1.75E-07	1.77E-07	5.81E-12	
RB-DI (SW)	2D	25	RHR Heat Exchanger Room B	6.70E-04	8.66E-05	8.68E-05	1.27E-10	Shut HPCI-MO-14 and RR-MO-53A.
RB-DI (SE)	1D/1E	26	RHR B/HPCI Pump Room	4.28E-03	6.48E-05	1.44E-04	3.37E-07	Shut HPCI-MO-14 and RR-MO-53A.
RB-J	3A	27	Switchgear Room 1F	3.71E-03	5.28E-05	5.28E-05	0.00E+00	Open RHR-MO-17, RHR-MO-25B, and RHR-MO-67
RB-K	3B	28	Switchgear Room 1G	3.71E-03	1.77E-02	1.77E-02	0.00E+00	Open RHR-MO-25A
RB-M	3C/3D /3E	29	RB Elevation 932	1.13E-02	7.06E-06	8.99E-06	2.18E-08	Open RHR-MO-17 and RHR-MO-25B
	2B	30	RHR Hx Rm A	6.70E-04	7.06E-06	8.99E-06	1.29E-09	

RB-N	3C/3D /3E	31	Reactor Building Elevation 932	1.13E-02	1.22E-05	1.38E-05	1.81E-08	Open RHR-MO-25A
	2D	32	RHR Heat Exchanger Room B	6.70E-04	1.22E-05	1.38E-05	1.07E-09	
TB-A	11D	33	Condenser Pit Area	3.10E-03	4.83E-06	6.20E-06	4.25E-09	Open RHR-MO-17, RHR-MO-25A, and RHR-MO-67
	11E	34	Reactor Feedwater Pump Area	6.25E-03	4.83E-06	6.20E-06	8.56E-09	
	11L	35	Pipe Chase	6.70E-04	4.83E-06	6.20E-06	9.18E-10	
	12C	36	Condenser and Heater Bay Area	3.27E-03	4.83E-06	6.20E-06	4.48E-09	
	12D	37	TB Floor 903	3.45E-03	4.83E-06	6.20E-06	4.73E-09	
	13A	38	Turbine Operating Floor	5.76E-03	4.83E-06	6.20E-06	7.89E-09	
	13B	39	Non-critical Switchgear Room	3.79E-03	4.83E-06	6.20E-06	5.19E-09	
	13C	40	Electric Shop	8.56E-04	4.83E-06	6.20E-06	1.17E-09	
	13D	41	I&C Shop	8.90E-04	4.83E-06	6.20E-06	1.22E-09	
Total Estimated ΔCDF for 41 Postulated Fire Scenarios:							2.91E-06	

Post-Fire Remote Shutdown Calculations:

As documented in Assumptions 4, 5, and 6, the analyst created a linked event tree model, using the Systems Analysis Programs for Hand-on Integrated Reliability Evaluation (SAPHIRE) software provided by the Idaho National Laboratory, to evaluate the risks related to fire-induced main control room abandonment at the Cooper Nuclear Station. This linked event tree was used to evaluate the increased risk from the subject performance deficiency during the response to postulated fires in the main control room, the auxiliary relay room, the cable spreading room, the cable expansion room or Fire Area RB-FN. The primary event tree used in this model is displayed as Figure 1 in the Attachment.

As documented in Assumption 5, the analyst used an event tree to evaluate the likelihood of operator recovery via either restoration of HPCI or manually opening Valve RHR-MO-25B. The resulting non-recovery probability was 7.9×10^{-2}.

Using the linked event tree model described in Assumption 4, the analyst calculated the ΔCDF to be 7.3×10^{-6}/yr. The dominant cutsets are shown below in Table 2.

Table 2
Main Control Room Abandonment Cutsets

Postulated Fire	Sequence	Mitigating Functions	Results
Auxiliary Relay Room	4-01-03	Failure to Reestablish HPCI Failure to Open MO-25B	1.7×10^{-6}/yr
Main Control Room	3-01-03	Failure to Reestablish HPCI Failure to Open MO-25B	4.5×10^{-7}/yr
Auxiliary Relay Room	4-01-12	Early HPCI Failure Failure to Open MO-25B	4.1×10^{-7}/yr
Auxiliary Relay Room	4-01-12	HPCI Out of Service Failure to Open MO-25B	2.7×10^{-7}/yr
Main Control Room	4-01-12	Early HPCI Failure Failure to Open MO-25B	1.1×10^{-7}/yr

Control Room Abandonment Frequency

NUREG/CR-2258, “Fire Risk Analysis for Nuclear Power Plants,” provides that control room evacuation would be required because of thick smoke if a fire went unsuppressed for 20 minutes. Given Assumption 6 and assuming that a fire takes 2 minutes to be detected by automatic detection and/or by the operators, there are 18 minutes remaining in which to suppress the fire prior to main control room evacuation being required. NRC Inspection Manual Chapter 0609, Appendix F, Table 2.7.1, “Non-suppression Probability Values for Manual Fire Fighting Based on Fire Duration (Time to Damage after Detection) and Fire Type Category,” provides a manual non-suppression probability (P_{NS}) for the control room of 1.3×10^{-2} given 18 minutes from time of detection until time of equipment damage. This is a reasonable approach, although fire modeling performed by the licensee indicated that 16 minutes was the expected time to abandon the main control room based on habitability.

In accordance with Inspection Manual Chapter 0609, Appendix F, Task 2.3.2, the analyst used a severity factor of 0.1 for determining the probability that a postulated fire would be self sustaining and grow to a size that could affect plant equipment.

Given these values, the analyst calculated the main control room evacuation frequency for fires in the main control room (F_{EVAC}) as follows:

$$F_{EVAC} = P_{FIF} * SF * P_{NS}$$

$$= 6.88 \times 10^{-3}/yr * 0.1 * 1.3 \times 10^{-2}$$

$$= 8.94 \times 10^{-6}/yr$$

In accordance with Procedure 5.4FIRE-S/D, operators are directed to evacuate the main control room and conduct a remote shutdown, if a fire in the main control room or any of the four areas documented in Assumption 8, if plant equipment spuriously actuates/de-energizes equipment, or if instrumentation becomes unreliable. Therefore, for all scenarios except a postulated fire in the main control room, the probability of non-suppression by automatic or manual means are documented in Table 3, below.

Table 3
Control Room Abandonment Frequency

Fire Area	Ignition Frequency (per year)	Severity	Automatic Suppression	Manual Suppression	Abandonment Frequency (per year)
Main Control Room	6.88×10^{-3}	0.1	none	1.3×10^{-2}	8.94×10^{-6}
Auxiliary Relay Room	1.42×10^{-3}	0.1	none	0.24	3.41×10^{-5}
Cable Expansion Room	1.69×10^{-4}	0.1	2×10^{-2}	0.24	8.11×10^{-8}
Cable Spreading Room	4.27×10^{-3}	0.1	5×10^{-2}	0.24	5.12×10^{-6}
Reactor Building 903’ (RB-FN)	1.43×10^{-3}	0.1	2×10^{-2}	0.24	6.86×10^{-7}
Total MCR Abandonment:					4.89×10^{-5}

The licensee's total control room abandonment frequency was 1.75×10^{-5}. For the main control room fire, the licensee's calculations were more in-depth than the analyst's. The remaining fire areas were assessed by the licensee using IPEEE data. However, the following issues were noted with the licensee's assessment:

Kitchen fires were not included in licensee's evaluation

- This would tend to increase the ignition frequency
- This might add more heat input than the electrical cabinet fires modeled by the licensee

Habitability Forced Abandonment

- Non-suppression probability did not account for fire brigade response time or the expected time to damage.
- Reduced risk based on 3 specific cabinets causing a loss of ventilation early, when it should have increased the risk. Fire modeling showed that fires in these cabinets could damage nearby cables and cause ventilation damper(s) to close.
- Risk Assessment Calculation ES-91 uses an abandonment value of 9.93×10^{-7}. However, the supporting calculation performed by EPM used 3.02×10^{-6}.

Equipment Failure Control Room Abandonment

- Criteria for leaving the control room did not accurately reflect the guidance that was proceduralized.
- The evaluation of the Cable Expansion Room stated that the only fire source was self-ignition of cables. This was modeled as a hot work fire, and it included a probability that administrative controls for hot work and fire watches would prevent such fires from getting large enough to require control room abandonment. This is inappropriate for self-ignition of cables, since there would not really be any fire watch present. Adjusting for this would increase the risk in this area by two orders of magnitude.
- The licensee concluded that fires in equipment in the four alternate shutdown fire areas outside the main control room (see Assumption 8) would not result in control room abandonment without providing a technical basis. The licensee's Appendix R analysis concluded that fire damage in these rooms require main control room evacuation to prevent core damage.

The analyst used the main control room abandonment frequencies documented in Table 3. In addition, sensitivities were run using the licensee's values.

<u>Recovery Following Failure of Valve RHR-MO-25B</u>

As documented in Assumption 5, the analyst calculated a combined non-recovery probability using the event tree shown in Figure 2 in the Attachment.

Table 4 documents the final split fractions used in quantifying this event tree.

Table 4
Split Fractions for RECOVERY-PATH

Top Event	How Assessed	Failure Probability
LEVEL-DOWN	SPAR-H (Diagnosis Only)	1.0×10^{-3}
SRV-STATUS	Best Estimate of Fraction	1.0×10^{-1}
CLOSE-SRVS	SPAR-H (Action Only)	5.0×10^{-4}
RESTORE-HPCI	SPAR-H (Combined)	5.1×10^{-3}
OPEN-MO-25B-3	SPAR-H (Combined)	5.0×10^{-1}
OPEN-MO-25B-5/7	SPAR-H (Combined)	5.5×10^{-2}

Using the event tree in Figure 2 and the split fractions in Table 4, the analyst calculated a combined non-recovery probability of 7.9×10^{-2}. The licensee's combined non-recovery probability was 4.0×10^{-3}. The licensee used a similar approach to quantify this value. However, the licensee assumed that operators would always shut the safety-relief valves upon determining that reactor pressure vessel water level was decreasing. The analyst assumed that some percentage of operators would continue to follow the procedure and attempt to recover from the failed RHR valve or try alternate methods of low-pressure injection. In addition, the analyst identified the following issues that impacted the licensee's analysis:

- The inspectors determined that it would require 112 ft-lbs of force to manually open Valve RHR-MO-25B. The analyst determined that this affected the ergonomics of this recovery. Some operators may assume that the valve is on the backseat when large forces are required to open it. Some operators might be incapable of applying this force to a 2-foot diameter hand wheel.

- The analyst noted that the following valves would be potential reasons for lack of injection flow and/or may distract operators from diagnosis that Valve RHR-MO-025B is closed:

    - RHR-81B, RHR Loop B Injection Shutoff Valve, could be closed.

    - RHR-27CV, RHR Loop B Injection Line Testable Check Valve, could be stuck closed.

- RHR-MO-274B, Injection Line Testable Check Valve Bypass Valve, could be opened as an alternative.

- Operators could search for an alternate flow path.

- The licensee's evaluation did not include sequences involving the failure of the HPCI system shortly after main control room evacuation in their risk evaluation. These sequences represented approximately 26 percent of the ΔCDF as calculated by the analyst. These sequences are important for the following reasons:

  - Failure of HPCI leads to the need for operators to rapidly depressurize the reactor to establish alternate shutdown cooling. Decay heat will be much higher than for sequences involving early HPCI success. Also, depressurization under high decay heat and high temperature result in greater water mass loss. This will significantly reduce the time available for recovery actions.

  - HPCI success sequences provide long time frames available with HPCI operating. This reduces decay heat, increases time for recovery, and permits the establishment of an emergency response organization. Those factors are not applicable to early HPCI failure sequences.

- The basis for operating HPCI was not well documented by the licensee. During many of the extended sequences, suppression pool temperature went well above the operating limits for HPCI cooling and remained high for extended periods of time. The following facts were determined through inspection:

  - The design temperature for operating HPCI is 140°F based on process flow providing oil cooling.

  - General Electric provided a transient operating temperature of 170°F for up to 2 hours.

  - In the licensee's best case evaluation of the performance deficiency, the suppression pool would remain above 150°F for 10.6 hours.

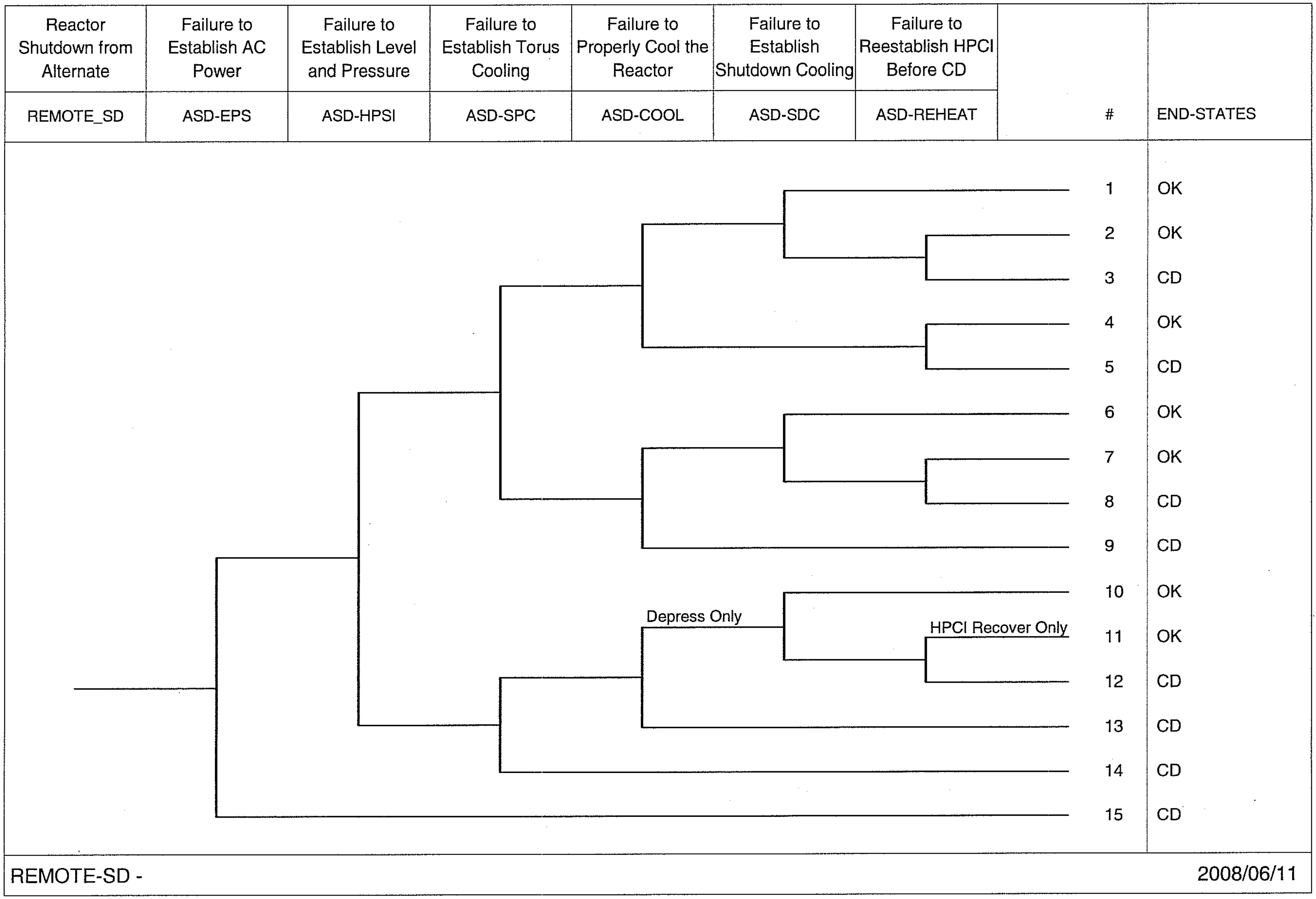
- The licensee used a case-specific combined recovery in assessing the risk of this performance deficiency. Most of the recoveries discussed by the licensee would have been available with or without the performance deficiency. Therefore, these should be in the baseline model and portions of the sequences subtracted from the case evaluation. This is the approach used by the analyst in the linked event trees model.

- The licensee stated during the regulatory conference that credit should be given for diesel-driven fire water pump injection. This is one of the licensee's alternate strategies. However, the inspectors determined, and the licensee concurred, that this alternate method of injection requires that Valve RHR-MO-25B be open. Therefore, no credit was given for this alternate strategy.

Conclusions:

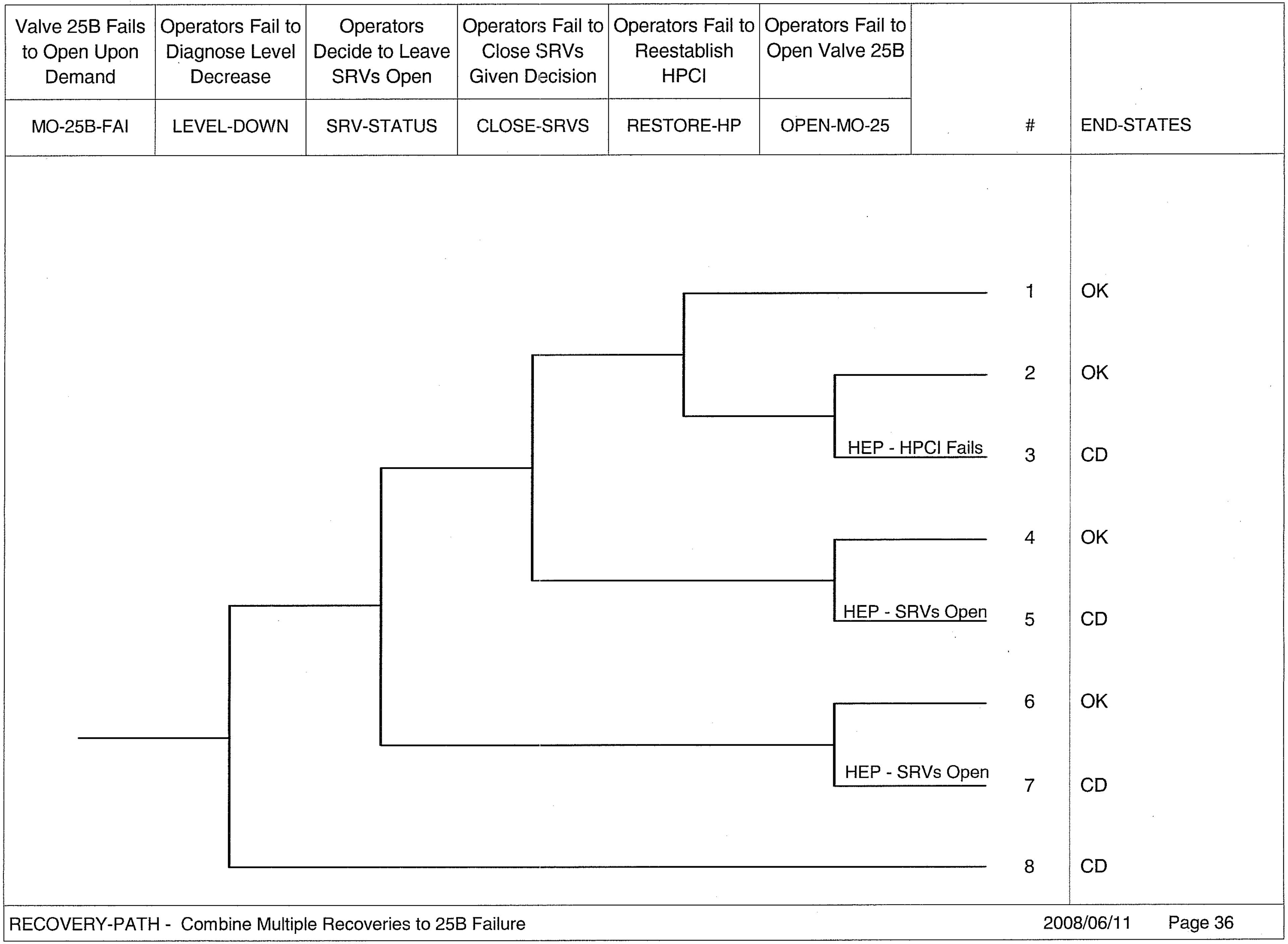
The analyst concluded that the subject performance deficiency was of low to moderate significance (White). As documented in Table 1, for a period of exposure of 1 year, the analyst determined a best estimate ΔCDF for fire scenarios that did not require evacuation of the main control room of 7.8×10^{-7} using both quantitative and qualitative techniques. Additionally, using the linked event tree model described in Assumption 4, for a period of exposure of 1 year, the analyst calculated the ΔCDF to be 7.3×10^{-6} for postulated fires leading to the abandonment of the main control room. This resulted in a total best estimate ΔCDF of 8.1×10^{-6}.

Figure 1



Reactor Shutdown from Alternate
Failure to Establish AC Power
Failure to Establish Level and Pressure
Failure to Establish Torus Cooling
Failure to Properly Cool the Reactor
Failure to Establish Shutdown Cooling
Failure to Reestablish HPCI Before CD
REMOTE_SD
ASD-EPS
ASD-HPSI
ASD-SPC
ASD-COOL
ASD-SDC
ASD-REHEAT
#
END-STATES
Depress Only
HPCI Recover Only
1 OK
2 OK
3 CD
4 OK
5 CD
6 OK
7 OK
8 CD
9 CD
10 OK
11 OK
12 CD
13 CD
14 CD
15 CD
REMOTE-SD -
2008/06/11

Figure 2


Valve 25B Fails to Open Upon Demand
Operators Fail to Diagnose Level Decrease
Operators Decide to Leave SRVs Open
Operators Fail to Close SRVs Given Decision
Operators Fail to Reestablish HPCI
Operators Fail to Open Valve 25B
MO-25B-FAI
LEVEL-DOWN
SRV-STATUS
CLOSE-SRVS
RESTORE-HP
OPEN-MO-25
#
END-STATES
HEP - HPCI Fails
HEP - SRVs Open
HEP - SRVs Open
1 OK
2 OK
3 CD
4 OK
5 CD
6 OK
7 CD
8 CD
RECOVERY-PATH - Combine Multiple Recoveries to 25B Failure
2008/06/11 Page 36

SUPPLEMENTAL INFORMATION

Summary of Findings

IR 05000298/2008008; 03/19/08 – 06/13/08; Cooper Nuclear Station: Triennial Fire Protection Follow-up Inspection

The report covered a 3-month period of inspection follow-up and significance determination efforts by region-based inspectors and a senior risk analyst. One finding with an associated violation was determined to have White safety significance. The significance of most findings is indicated by its color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

White. A violation of 10 CFR Part 50, Appendix B, Criterion V, was identified for failure to ensure that some steps contained in emergency procedures at Cooper Nuclear Station would work as written. Inspectors identified that steps in Emergency Procedures 5.4POST-FIRE, "Post-Fire Operational Information," and 5.4FIRE-S/D, "Fire Induced Shutdown From Outside Control Room," intended to reposition motor-operated valves locally, would not have worked as written because the steps were not appropriate for the configuration of the motor-starter circuits. This condition existed between 2004 and June, 2007. Appendix B to 10 CRF 50, Criterion V, was not met because these quality-related procedures would not work to allow operators to bring the plant to a safe shutdown condition in the event of certain fires. This finding had a cross-cutting aspect in Problem Identification and Resolution, under the Corrective Action Program attribute, because the licensee did not thoroughly evaluate the 2004 NRC violation to address causes and extent of condition (P.1.c -Evaluations).

This finding is of greater than minor safety significance because it impacted the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This finding affected both the procedure quality and protection against external factors (fires) attributes of this cornerstone objective. This finding was determined to have a White safety significance during a Phase 3 evaluation. The scenarios of concern involve larger fires in specific areas of the plant which trigger operators to implement fire response procedures to place the plant in a safe shutdown condition. Since some of those actions could not be completed using the procedures as written, this would challenge the operators' ability to establish adequate core cooling.

KEY POINTS OF CONTACT

Licensee

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LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Discussed

05000298/2008007-01	VIO	Two Inadequate Post-Fire Safe Shutdown Procedures

LIST OF DOCUMENTS REVIEWED

PROCEDURES

Number	Title	Revision
Administrative Procedure 0.1	Procedure Use and Adherence	31
Administrative Procedure 0.4A	Procedure Change Process Supplement	various
Administrative Procedure 2.0.1.2	Operations Procedure Policy	27
Administrative Procedure 2.0.3	Conduct of Operations	58
Emergency Procedure 5.4 Fire	General Fire Procedure	14
Emergency Procedure 5.4 Post-Fire	Post-Fire Operational Information	12 & 13
Emergency Procedure 5.4 Fire-S/D	Fire Induced Shutdown From Outside Control Room	14 & 15

SELF-ASSESSMENTS AND AUDITS

QA Audit 07-01	Fire Protection Program	02/2007
Self-assessment	Manual Action Feasibility – Review of Cooper Nuclear Station Post-Fire Manual Actions With NRC Inspection Manual Post-Fire Manual Action Feasibility Criteria	05/18/07
Procedure Change Request	Emergency Procedure 5.4 POST-FIRE, Post Fire Operational Information	Revision 4
Alarm Response Procedure 2.3_9-3-2, Panel 9-3-2/D-1	HPCI Turbine Oil Cooler Temperature High	Revision 17

CONDITION REPORTS

2007-04155
2004-03034
2004-03081
2003-05433

CALCULATIONS

Fauske Review of Cooper Nuclear Station Calculation NEDC 08-035, “Suppression Pool Heat-up Response for Appendix R Event with 24 Hour HPCI Operation.”

Calculation NEDC 08-035, “Suppression Pool Heat-up Response for Appendix R Event with 24 Hour HPCI Operation,” Revision 0.

Calculation NEDC 08-041, “Main Control Room Forced Abandonment Fire Scenario Analysis,” Revision 0.

EPM Calculation P1906-07-011b-001, “Main Control Room Forced Abandonment Fire Scenario Analysis,”5/2008.

Calculation ES-091, “Detailed PSA Study of Fire Protection Triennial Inspection,” Revision 0.

Calculation NEDC 08-032, EPM Calculation 1906-07-06, “Fire Ignition Frequencies,” Revision 0.

MISCELLANEOUS

White paper discussion on SRV circuit operation from the alternate shutdown panel dated 5/19/2008.

GE Service Information Letter 615, “ADS/HPCI Functional Redundancy,” dated 3/4/1998.

NUREG 2258, “Fire Risk Analysis for Nuclear Power Plants.”

NUREG/CR-6850, “EPRI/NRC-RES Fire PRA Methodology for Nuclear Power Facilities.”

NPPD Letter NLS2008044, “Additional Information for Consideration in Addressing Inspection Finding,” dated 5/8/2008.

Generic Letter 82-21, “Technical Specifications for Fire Protection Audits.”

NRC Inspection Report 05000317/2007009 and 05000318/2007009.

NRC Inspection Report 05000282/2006009 and 05000306/2006009.

NRC Inspection Report 05000261/2007007.

Additional documents reviewed as part of inspecting this finding are documented in NRC Inspection Report 05000298/2008007.