UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

August 12, 2004

EA-04-131

Randall K. Edington, Vice
President-Nuclear and CNO
Nebraska Public Power District
P.O. Box 98
Brownville, NE 68321

SUBJECT: COOPER NUCLEAR STATION - NRC INSPECTION REPORT 05000298/2004014; PRELIMINARY GREATER THAN GREEN FINDING

Dear Mr. Edington:

On July 15, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Cooper Nuclear Station. The purpose of the inspection was to follow up on the misalignment of the service water system that rendered one train of service water inoperable for a period of 21 days. The enclosed inspection report documents an inspection finding which was discussed on July 22, 2004, with Mr. J. Roberts, Director of Nuclear Safety Assurance, and other members of your staff.

The report discusses a finding that appears to have Greater than Green safety significance. As described in Section 1R04 of this report, this issue involved the failure to restore the Division 2 service water gland water supply to a normal alignment on January 21, 2004, following maintenance on the Division 2 service water discharge strainer. This error went undetected until February 11, 2004, when a low pressure alarm prompted operators to perform a confirmatory valve alignment during which it was discovered that the Division 2 gland water supply was cross-connected with the Division 1 supply. This resulted in Division 2 of the service water system and Emergency Diesel Generator 2 being inoperable for 21 days. This finding was assessed based on the best available information, including influential assumptions, using the applicable Significance Determination Process and was preliminarily determined to be a Greater than Green finding. Because the preliminary safety significance is Greater than Green, the NRC requests that additional information be provided regarding the nonrecovery probability for Division 2 of the service water system and any other considerations you have identified as impacting the safety significance determination, such as those documented in Section 1R04.b in the enclosed report.

This finding does not present a current safety concern because the valve lineup was restored to the normal configuration. Also, the affected equipment was returned to an operable condition.

This finding is also an apparent violation of NRC requirements and is being considered for escalated enforcement action in accordance with the “General Statement of Policy and Procedure for NRC Enforcement Actions” (Enforcement Policy), NUREG-1600. The current enforcement policy is included on the NRC’s website at http://www.nrc.gov/what-we-do/regulatory/enforcement.html.

Before the NRC makes a final decision on this matter, we are providing you an opportunity (1) to present to the NRC your perspectives on the facts and assumptions, used by the NRC to arrive at the finding and its significance, at a Regulatory Conference or (2) submit your position on the finding to the NRC in writing. We note that in a letter to the NRC dated August 9, 2004, NPPD submitted information related to the safety significance of this issue. The NRC will consider this information prior to making a final decision on this matter. If you request a Regulatory Conference, it should be held within 30 days of the receipt of this letter and we encourage you to submit any additional supporting documentation at least one week prior to the conference in an effort to make the conference more efficient and effective. If a Regulatory Conference is held, it will be open for public observation. If you decide to submit only a written response, such submittal should be sent to the NRC within 30 days of the receipt of this letter.

Please contact Mr. Kriss Kennedy at (817) 860-8144 within 10 business days of the date of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision and you will be advised by separate correspondence of the results of our deliberations on this matter.

Since the NRC has not made a final determination in this matter, no Notice of Violation is being issued for the inspection finding at this time. In addition, please be advised that the characterization of the apparent violation described in the enclosed inspection report may change as a result of further NRC review.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC’s document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/RA/

Arthur T. Howell III, Director
Division of Reactor Projects

Docket: 50-298
License: DPR-46

Enclosure:
NRC Inspection Report 05000298/2004014
w/attachment: Supplemental Information

cc w/enclosure:
Clay C. Warren, Vice President of
Strategic Programs
Nebraska Public Power District
1414 15th Street
Columbus, NE 68601

John R. McPhail, General Counsel
Nebraska Public Power District
P.O. Box 499
Columbus, NE 68602-0499

P. V. Fleming, Licensing Manager
Nebraska Public Power District
P.O. Box 98
Brownville, NE 68321

Michael J. Linder, Director
Nebraska Department of
Environmental Quality
P.O. Box 98922
Lincoln, NE 68509-8922

Chairman
Nemaha County Board of Commissioners
Nemaha County Courthouse
1824 N Street
Auburn, NE 68305

Sue Semerena, Section Administrator
Nebraska Health and Human Services System
Division of Public Health Assurance
Consumer Services Section
301 Centennial Mall, South
P.O. Box 95007
Lincoln, NE 68509-5007

Ronald A. Kucera, Deputy Director
for Public Policy
Department of Natural Resources
P.O. Box 176
Jefferson City, MO 65101

Jerry Uhlmann, Director
State Emergency Management Agency
P.O. Box 116
Jefferson City, MO 65102-0116

Chief, Radiation and Asbestos
Control Section
Kansas Department of Health
and Environment
Bureau of Air and Radiation
1000 SW Jackson, Suite 310
Topeka, KS 66612-1366

Daniel K. McGhee
Bureau of Radiological Health
Iowa Department of Public Health
401 SW 7th Street, Suite D
Des Moines, IA 50309

William J. Fehrman, President
and Chief Executive Officer
Nebraska Public Power District
1414 15th Street
Columbus, NE 68601

Jerry C. Roberts, Director of
Nuclear Safety Assurance
Nebraska Public Power District
P.O. Box 98
Brownville, NE 68321

Chief Technological Services Branch
National Preparedness Division
Department of Homeland Security
Emergency Preparedness & Response Directorate
FEMA Region VII
2323 Grand Boulevard, Suite 900
Kansas City, MO 64108-2670

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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket.:	50-298
License:	DPR 46
Report:	05000298/2004014
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	P.O. Box 98 Brownville, Nebraska
Dates:	March 25 through July 15, 2004
Inspectors:	S. Schwind, Senior Resident Inspector S. Cochrum, Resident Inspector D. Loveless, Senior Reactor Analyst
Approved By:	A. Howell III, Director, Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR05000298/2004014; 03/25/04 - 07/15/04; Cooper Nuclear Station; Equipment Alignment.

The report documents the NRC's inspection of the misalignment of the service water system that existed for 21 days. The inspection identified one finding whose safety significance has preliminarily been determined to be Greater than Green. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process." 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

Cornerstone: Mitigating Systems

- TBD. A self-revealing apparent violation of 10 CFR Part 50, Appendix B, Criterion V, was identified for the failure to provide adequate instructions for restoring the service water system to an operable configuration following the completion of maintenance activities. This condition existed from January 21 through February 11, 2004, and resulted in Division 2 of the service water system as well as Emergency Diesel Generator 2 being inoperable for 21 days.

  The finding was greater than minor because it affected the reliability of the service water system, which is relied upon to mitigate the effects of an accident. The finding was determined to have a potential safety significance greater than very low significance (i.e., Greater than Green) because it caused an increase in the likelihood of an initiating event, namely, a loss of service water, as well as increasing the probability that the service water system would not be available to perform its mitigating systems function (Section 1R04).

REPORT DETAILS

1. REACTOR SAFETY
Cornerstones: Mitigating Systems

1R04 Equipment Alignment

a. Inspection Scope

The inspectors reviewed the root cause analysis and corrective actions regarding the failure to restore Division 2 of the service water (SW) system to normal alignment following maintenance on January 21, 2004.

b. Findings

(1) Introduction. A self-revealing apparent violation of 10 CFR Part 50, Appendix B, Criterion V, was identified for the failure to provide adequate instructions for restoring the SW system to an operable configuration following the completion of maintenance activities on January 21, 2004. This resulted in Division 2 of the SW system being inoperable from January 21 through February 11, 2004.

(2) Description. Cooper Nuclear Station is equipped with two divisions of SW, Divisions 1 and 2, each containing two pumps. The two pumps in each division discharge to a common header. Service water passes through a discharge strainer and continues through the system. Gland water is supplied to each pump from a connection downstream of the discharge strainer in the respective divisions. The gland water in each division supplies cooling and lubricating water to the pump shaft bearings. Gland water is required to support the operability of the service water pumps. A cross-connect line exists between the Divisions 1 and 2 gland water supplies which is only used during maintenance activities. By procedure, if the Divisions 1 and 2 gland water supplies are cross-connected, the division of SW that is not supplying its own gland water must be declared inoperable.

On February 8, control room operators received trouble alarms on both the Divisions 1 and 2 SW gland water supplies. In accordance with the alarm response procedure, an operator was dispatched to the SW pump room where it was determined that the alarm was caused by low pressure on each of the gland water systems. There are no operability limits associated with gland water pressure, only gland water flow, which was verified to be acceptable. The alarm cleared and no further actions were taken. The occurrence was documented in the corrective action program as Notification 1029449.

On February 11, an additional trouble alarm was received on the Division 2 service water gland water supply. The gland water flow was found to be acceptable and the alarm cleared; however, the licensee performed the additional action of verifying the gland water valve lineup. As a result, operators discovered that the Division 2 gland water supply valve (SW-28) was shut and the cross-connect valves (SW-1479 & SW-1480) were open. This configuration was not in accordance with System Operating

Procedure (SOP) 2.2.71, “Service Water System,” Revision 69. In response, the licensee immediately declared Division 2 of the SW system inoperable and entered Technical Specification 3.7.2, which required operators to restore the inoperable division of SW to an operable status within 30 days or place the plant in a hot shutdown condition within 12 hours. Emergency Diesel Generator 2, Division 2 of the residual heat removal system, and Division 2 of the reactor equipment cooling system, were declared inoperable as well, since SW is required to support operability of these systems. The licensee immediately restored the valve lineup per SOP 2.2.71, and the affected equipment was declared operable.

The licensee documented this valve misalignment issue in their corrective action program as Significant Condition Report 2004-0077. The subsequent investigation determined that the valve misalignment had existed since routine preventive maintenance had been performed on the Division 2 SW discharge strainer on January 21, approximately 21 days. Clearance Order SWB-1-4324147 SW-STNR-B was issued in support of this maintenance, which required the strainer to be removed from service in accordance with SOP 2.2.71. SOP 2.2.71, Section 13, “Securing SW Zurn Strainer,” directed operators to open the gland water cross-connect valves and shut the Division 2 supply valve (SW-28). The clearance order was released later the same day following completion of the maintenance. The instructions (release notes) on the clearance order directed operators to “release tags and restart [the] strainer IAW [in accordance with SOP] 2.2.71.” Operators utilized SOP 2.2.71, Section 12, “Starting SW Zurn Strainer,” to restart the strainer. However, Section 12 to did not contain instructions to restore the gland water supply to its normal configuration. Those instructions were located in Section 10, “SW Gland Water Subsystem B Operation,” which was not referenced by the tagout and was not used by personnel during system restoration. As a result, upon completion of the activity, operators declared Division 2 of SW operable, unaware that the gland water systems remained cross-connected.

(3) <u>Analysis</u>. The failure to establish appropriate procedural guidance for the restoration of the Division 2 SW pump gland water supply following maintenance and prior to returning the system to service was considered to be a performance deficiency. This deficiency resulted in the Division 2 SW pump gland water being provided by the Division 1 SW pumps. In this configuration, a failure of the Division 1 pumps would have resulted in loss of gland water to the Division 2 pumps and the potential loss of all SW. This finding affected both the Initiating Events Cornerstone and the Mitigating Systems Cornerstone and was more than minor since it affected the reliability of the SW system, which provides the ultimate heat sink for the reactor during accident conditions.

<u>Significance Determination</u>

The analysts reviewed the performance deficiency to determine the appropriate risk characterization. In summary, the performance deficiency was determined to be a finding that was more than minor and required a Phase 2 estimation. The Phase 2 process estimated the color of the finding as YELLOW and finding-specific data indicated the necessity for a Phase 3 evaluation. The analyst developed the preliminary

Phase 3 results as presented in Table 3.a. The total change in core damage frequency (CDF) was estimated to be 1.0×10^{-5} and the total change in large early release frequency (LERF) was estimated to be 9.5×10^{-6}. The assumptions and considerations used in the evaluation are presented below.

(a) Phase 1 Screening Logic, Results and Assumptions

The inspectors evaluated the issue using the SDP Phase 1 Screening Worksheet for the Initiating Events, Mitigating Systems, and Barriers Cornerstones provided in Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." This issue caused an increase in the likelihood of an initiating event, namely, a loss of SW (TSW), as well as increasing the probability that the SW system would not be available to perform its mitigating systems function. Therefore, a Phase 2 analysis was performed.

(b) Phase 2 Estimation for Internal Events

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, "User Guidance for Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors evaluated the subject finding using the Risk-Informed Inspection Notebook for Cooper Nuclear Station, Revision 1. The following assumptions were made:

- The failure of gland water cooling to an SW pump will result in the failure of the pump to meet its risk-significant function.
- The configuration of the SW system increased the likelihood that all SW would be lost.
- The condition existed for 21 days. Therefore, the exposure time window used was 3 - 30 days.
- No credit for recovery was given since there was insufficient time to implement recovery actions and there was no procedural guidance requiring operators to verify the valve lineup upon receipt of an SW gland water trouble alarm.
- The initiating event likelihood credit for TSW system was increased from five to four by the senior reactor analyst in accordance with Usage Rule 1.2 in Inspection Manual Chapter 0609, Appendix A, Attachment 2, "Site Specific Risk-Informed Inspection Notebook Usage Rules." This change reflects the fact that the finding increased the likelihood of a TSW, a normally cross-tied support system.

- The configuration of the SW system did not increase the probability that the system function would be lost by an order of magnitude because both pumps in Division I would have to be lost before the condition would affect Division II. Therefore, the order of magnitude assumption was that the SW system would continue to be a multitrain system.

- Because both divisions of SW continued to run and would have been available without an independent loss of Division I, this condition decreased the reliability of the system, but not the function. Therefore, sequences with loss of the SW mitigating function were not included in the analysis.

The last two assumptions are a deviation from the risk-informed notebook. This deviation represents a Phase 3 analysis in accordance with Inspection Manual Chapter 0609, Appendix A, Attachment 1, in the section entitled: "Phase 3 - Risk Significance Estimation Using Any Risk Basis That Departs from the Phase 1 or 2 Process."

Table 2 of the risk-informed notebook requires that all initiating event scenarios be evaluated when a performance deficiency affects the SW system. However, given the assumption that the SW system function was not degraded, only the sequences with the special initiator for TSW and the sequences related to a loss of A/C are applicable to this evaluation. The sequences from the notebook are presented in Table 1, as follows:

Table 1: Phase 2 Sequences

Initiating Event	Sequence	Mitigating Functions	Results
Loss of SW	1	RECSW24-LI	6
Loss of SW	2	RCIC-LI	6
Loss of SW	3	RCIC-HPCI	6
Loss of Critical 4160V Bus F	1	NONE	6
Loss of Critical 4160V Bus F	2	HPI	8

Using the counting rule worksheet, this finding was estimated to be YELLOW. However, because several assumptions made during the Phase 2 process were either overly conservative or did not represent the actual configuration of the system, a Phase 3 evaluation was required.

(c) Phase 3 Analysis

1) Internal Initiating Events

Assumptions:

The results from the risk-informed notebook estimation were compared with an evaluation developed using a Standardized Plant Analysis Risk (SPAR) model simulation of the cross-tied SW divisions, as well as an assessment of the licensee's evaluation provided by the licensee's probabilistic risk assessment staff. The SPAR runs were developed on the basis of the following analyst assumptions:

a) The Cooper SPAR model was revised to better reflect the failure logic for the SW system. This model, including the component test and maintenance basic events, represents an appropriate tool for evaluation of the subject finding.

b) NUREG/CR-5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980 - 1996," contains the NRC's current best estimate of both the likelihood of each of the loss of offsite power (LOOP) classes (i.e., plant-centered, grid related, and severe weather) and their recovery probabilities.

c) The SW pumps at Cooper will fail to run if gland water is lost for 30 minutes or more. If gland water is recovered within 30 minutes of loss, the pumps will continue to run for their mission time, given their nominal failure rates.

d) The condition existed for 21 days from January 21 through February 11, 2004, representing the exposure time.

e) The nominal likelihood for a loss of SW, $IEL_{(TSW),}$ at the Cooper Nuclear Station is as stated in NUREG/CR-5750, "Rates of Initiating Events at Nuclear Power Plants: 1987 - 1995," Section 4.4.8, "Loss of Safety-Related Cooling Water System." This reference documents a total loss of SW frequency at 9.72×10^{-4} per critical year.

f) The nominal likelihood for a partial loss of SW, $IEL_{(PTSW)}$, at the Cooper Nuclear Station is as stated in NUREG/CR-5750, "Rates of Initiating Events at Nuclear Power Plants: 1987 - 1995," Section 4.4.8, "Loss of Safety-Related Cooling Water System." This reference documents a partial loss of SW frequency (loss of single division) at 8.92×10^{-3} per critical year.

g) The configuration of the SW system increased the likelihood that all SW would be lost. The increase in TSW initiating event likelihood best representing the change caused by this finding is one half the nominal likelihood for the loss of a single division. The analyst noted that the nominal value represents the likelihood that either division of SW is lost. However, for this finding, only losses of Division I equipment result in the loss of the other division.

h) The SPAR-H method used by Idaho National Engineering and Environmental Laboratories (INEEL) during the development of the SPAR models and published in Draft NUREG/CR-xxxxx, INEEL/EXT-02-10307, “SPAR-H Method,” is an appropriate tool for evaluating the probability of operators recovering from a loss of Division I SW.

i) The probability of operators failing to properly diagnose the need to restore Division II SW gland water upon a loss of Division I SW is 0.4. This assumed the nominal diagnosis failure rate of 0.01 multiplied by the following performance shaping factors:

- Available Time: 10

  The available time was barely adequate to complete the diagnosis. The analyst assumed that the diagnosis portion of this condition included all activities to identify the mispositioned valves. A licensee operator took 21 minutes to complete the steps during a simulation of the operator response to a failure of Division I SW. The analyst noted that this walkthrough did not require operators to prioritize many different annunciators that would be evident during the postulated plant conditions of interest. Additionally, operations personnel had been briefed on the finding at a time prior to the walkthrough, so they were more knowledgeable of the potential problem than they would have been prior to the identification of the finding.

- Stress: 2

  Stress under the conditions postulated would be high. Multiple alarms would be initiated, including a loss of the Division I SW and the loss of gland water to Division II. Additionally, the operators would understand that the consequences of their actions would represent a threat to plant safety.

- Complexity: 2

  The complexity of the tasks necessary to properly diagnose this condition was determined to be moderately complex. The analyst determined that all indications for proper diagnosis would be available; however, there was some ambiguity in the diagnosis of this condition. The following factors were considered:

- Division I would be lost and may be prioritized above Division II.

- The diagnosis takes place at both the main control room and the auxiliary panel in the SW structure and requires interaction between at least two operators.

- There have previously been alarms on gland water annunciators when swapping Divisions. Therefore, operators may hesitate to take action on Division II, given problems with Division I.

- Previous heat exchanger clogging events may mislead the operators during their diagnosis.

2) Initiating Event Calculation: The analyst used Assumptions e, f, and g calculated the new initiating event likelihood, $IEL_{(TSW\text{-}case)}$, as follows:

$IEL_{(TSW\text{-}case)} = IEL_{(TSW)} + [\ ½ *\ IEL_{(PTSW)}\ ] =$

$9.72 \times 10^{-4} + [\ 0.5 * 8.92 \times 10^{-3}\ ] =$

$5.43 \times 10^{-3}/\ yr \div 8760\ hrs/yr$

$6.20 \times 10^{-7}/hr.$

3) Evaluation of Change in Risk: Using Assumptions a) and b), the analyst modified Revision 3.03 of the SPAR model to include updated LOOP curves as published in NUREG CR-5496. The changes to the LOOP recovery actions, change in diesel generator mission time, and other modifications to the SPAR model were documented in Table 2. In addition, the failure logic for the SW system was significantly changed as documented in Assumption a). These revisions were incorporated into a base case update, making the modified SPAR model the baseline for this evaluation. The resulting baseline CDF, CDF_{base}, was 4.82×10^{-9} /hr.

The analyst changed this modified model to reflect that the failure of the Division I SW system would cause the failure of the gland water to Division II. Division II was then modeled to fail either from independent divisional equipment failures or from the failure of Division I. The analyst determined that the failure of Division II could be prevented by operator recovery action. As stated in

Assumption i), the analyst assumed that this recovery action would fail 40 percent of the time. The model was requantified with the resulting current case conditional CDF, CDF_{case}, of 1.74×10^{-8} /hr.

The change in ΔCDF from the model was:

$$\Delta CDF = CDF_{case} - CDF_{base}$$
$$= 1.74 \times 10^{-8} - 4.82 \times 10^{-9} = 1.26 \times 10^{-8} \text{ /hr.}$$

Therefore, the total ΔCDF from internal initiators over the exposure time that was related to this finding was calculated as:

$$\Delta CDF = 1.26 \times 10^{-8} \text{ /hr} * 24 \text{ hr/day} * 21 \text{ days} = 6.35 \times 10^{-6} \text{ for 21 days}$$

The risk significance of this finding is presented in Table 3.a. The dominant cutsets from the internal risk model are shown in Table 3.b.

Table 2: Baseline Revisions to SPAR Model

Basic Event	Title	Original	Revised
ACP-XHE-NOREC-30	Operator Fails to Recover AC Power in 30 Minutes	.22	5.14×10^{-1}
ACP-XHE-NOREC-4H	Operator Fails to Recover ac Power in 4 Hours	.023	6.8×10^{-2}
ACP-XHE-NOREC-90	Operator Fails to Recover ac Power in 90 Minutes	.061	2.35×10^{-1}
ACP-XHE-NOREC-BD	Operator Fails to Recover ac Power before Battery Depletion	.023	6.8×10^{-2}
IE-LOOP	Loss of Offsite Power Initiator	5.20×10^{-6}/hr	5.32×10^{-6}/hr
EPS-DGN-FR-FTRE	Diesel Generator Fails to Run - Early Time Frame	0.5 hrs.	0.5 hrs.
EPS-DGN-FR-FTRM	Diesel Generator Fails to Run - Middle Time Frame*	2.5 hrs.	13.5 hrs.
OEP-XHE-NOREC-10H	Operator Fails to Recover ac Power in 10 Hours	2.9×10^{-2}	5.6×10^{-2}
OEP-XHE-NOREC-1H	Operator Fails to Recover ac Power in 1 Hour	1.2×10^{-1}	3.93×10^{-1}

(continued) Basic Event	Title	Original	Revised
OEP-XHE-NOREC-2H	Operator Fails to Recover ac Power in 2 Hours	6.4×10^{-2}	2.49×10^{-1}
OEP-XHE-NOREC-4H	Operator Fails to Recover ac Power in 4 Hours	4.5×10^{-2}	1.36×10^{-1}
* Diesel Mission Time was increased from 2.5 to 14 hours to account for the increased time expected to recover offsite power derived from data analysis published in NUREG/CR-5496.			

Table 3.a: Phase 3 Analysis Results

Model	Result	CDF	LERF
SPAR 3.03, Revised	Baseline: Internal Risk	4.8×10^{-9}/hr	4.4×10^{-9}/hr
	Internal Events Risk	1.7×10^{-8}/hr	1.7×10^{-8}/hr
	TOTAL Internal Risk (ΔCDF)	6.4×10^{-6}	6.3×10^{-6}
	Baseline: External Risk	7.9×10^{-11}/hr	[1] 7.2×10^{-11}/hr
	External Events Risk	7.1×10^{-9}/hr	[1] 6.5×10^{-9}/hr
	TOTAL External Risk (ΔCDF)	3.6×10^{-6}	3.2×10^{-6}
	TOTAL Internal and External Change	1.0×10^{-5}	9.5×10^{-6}
NOTE 1: To simplify the data analysis, the analyst assumed that the ratio of high and low pressure sequences were the same as for internal events baseline. This has been accepted practice for achieving a reasonable approximation for ΔLERF.			

Table 3.b: Top Risk Cutsets

Initiating Event	Sequence Number	Sequence	Importance
LOOP	39-04	EPS-VA3-AC4H	1.4×10^{-8}
	39-10	EPS-RCI-VA3-AC4H	7.6×10^{-10}
	39-14	EPS-RCI-HCI-AC30MIN	5.2×10^{-10}
	39-24	EPS-SRVP2	3.2×10^{-10}
	39-22	EPS-SRVP1-RCI-VA3-AC90MIN	8.4×10^{-11}

(continued) Initiating Event	Sequence Number	Sequence	Importance
	7	SPC-SDC-CSS-CVS	5.4×10^{-11}
	36	RCI-HCI-DEP	4.7×10^{-11}
	6	SPC-SDC-CSS-VA1	4.6×10^{-11}
	39-23	EPS-SRVP1-RCI-HCI	2.7×10^{-11}
Transient	62	SRV-P1-PCS-MFW-CDS-LCS	6.0×10^{-10}
	63-05	PCS-SRVP1-SPC-CSS-VA1	2.9×10^{-10}
	64-11	PCS-SRVP2-LCS-LCI	1.0×10^{-10}
	9	PCS-SPC-SDC-CSS-CR1-VA1	3.7×10^{-11}
	63-06	PCS-SRVP1-SPC-CSS-CVS	2.9×10^{-11}
	63-32	PCS-SRVP1-RCI-HCI-DE2	2.6×10^{-11}
Loss of SW System	9	PC1-SPC-SDC-CSS-CR1-VA1	2.2×10^{-11}

2) External Initiating Events:

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, step 2.5, "Screening for the Potential Risk Contribution Due to External Initiating Events," the analyst assessed the impact of external initiators because the Phase 2 SDP result provided a Risk Significance Estimation of 7 or greater.

a) Seismic, High Winds, Floods, and Other External Events:

The analyst determined, through plant walkdown, that the major divisional equipment associated with the SW system were on the same physical elevation as its redundant equipment in the alternate division. All four SW pumps are located in the same room at the same elevation. Both primary switchgear are at the same elevation and in adjacent rooms. Therefore, the likelihood that internal or external flooding and/or seismic events would affect one division without affecting the other was considered to be extremely low. Likewise, high wind events and transportation events were assumed to affect both divisions equally.

b) Fire:

The analyst evaluated the list of fire areas documented in the licensee's fire plan and concluded that the Division I SW system could fail in internal fires that did not directly affect Division II equipment. These fires would constitute a change in risk associated with the finding. As presented in Table 4, the analyst identified two fire areas of concern: pump room fires and a fire in Switchgear 1F. Given that all four SW pumps are located in one room, three different fire sizes were evaluated, namely: one-pump fires, three-pump fires, and four-pump fires.

In the Individual Plant Examination for External Events Report - Cooper Nuclear Station (IPEEE), the licensee calculated the risk associated with fires in the SW pump room (Fire Area 20A). The related probabilities for these fires were as follows:

Table 4.a: Internal Fire Probabilities

Parameter	Variable	Probability
Fire Ignition Frequency	L_{Fire}	6.55×10^{-3}/yr
Conditional Probability of a Large Oil Spill	$P_{Large\ Spill}$	0.18
Conditional Probability of Fire less than 3 minutes	$P_{Short\ Fire}$	0.10
Conditional Probability of Unsuccessful Halon	P_{Halon}	0.05
Probability of Losing One Division I Pump in a One Pump Fire	P_{1-1}	0.5
Probability of Losing Both Division I Pumps in a Three Pump Fire	P_{2-3}	0.5
Probability of Losing One Division I Pump in a Three Pump Fire	P_{1-3}	0.5
Conditional Probability of Losing the Running Division I Pump Given a Fire Damaging a Single Pump	P_{run-1}	0.5
Failure to Run Likelihood for a SW Pump	L_{FTR}	3.0×10^{-5}/hr
Failure to Start Probability per Demand for an SW Pump	P_{FTS}	3.0×10^{-3}

As described in the IPEEE, the licensee determined that there were three different potential fire scenarios in the SW pump room, namely: a fire damaging one pump, caused by a small oil-spill fire limited to a 2-quart spill from the lower bearing reservoir associated with that pump; a fire that results from the spill of all the oil from a single pump (28 quarts), spreading rapidly, and damaging three pumps; and fires that affect all four pumps. The licensee had determined that fires affecting only two pumps were not likely, because of the nature of oil spills and spreading calculations. The analyst determined that a four-pump fire was part of the baseline risk; therefore, it would not be evaluated. A one-pump fire would not automatically result in a plant transient. However, the analyst assumed that a three-pump fire affecting both of the Division I pumps, would result in a TSW system initiating event.

The IPEEE stated that a single pump would be damaged in an oil fire that resulted from a small spill of oil, $L_{One\ Pump}$. The analyst, therefore, calculated the likelihood that a fire would damage a single pump as follows:

$$L_{One\ Pump} = L_{Fire} * (1 - P_{Large\ Spill})$$

$$= 6.55 \times 10^{-3}/yr \div 8760\ hrs/yr * (1 - 0.18)$$

$$= 6.78 \times 10^{-7}/hr$$

As in the IPEEE, the analyst assumed that all pumps would be damaged in an oil fire that resulted from a large spill of oil, that lasted for less than 3 minutes, if the Halon system failed to actuate. The intensity of an oil fire is dependent on the availability of oxygen, and the fire is assumed to continue until all oil is consumed or extinguished. Therefore, the shorter the duration of the fire, the higher its intensity and the more likely it is to damage equipment in the pump room. Should the fire last for less than 3 minutes and the Halon system successfully actuates, or if the fire lasts longer than 3 minutes, the licensee determined that a single pump would survive the fire, $L_{Three\ Pumps}$. The analyst, therefore, calculated the likelihood that a fire would damage three pumps as follows:

$$L_{Three\ Pumps} = [L_{Fire} * P_{Large\ Spill} * P_{Short\ Fire} * (1 - P_{Halon})] + [L_{Fire} * P_{Large\ Spill} * (1 - P_{Short\ Fire})]$$

$$= [6.55 \times 10^{-3}/yr \div 8760\ hrs/yr * 0.18 * 0.10 * (1 - 0.05)] + [6.55 \times 10^{-3}/yr \div 8760\ hrs/yr * 0.18 * (1 - 0.10)]$$

$$= 1.34 \times 10^{-7}/hr$$

The likelihood of a single pump in Division 1 being damaged because of a fire, $L_{Div1\ Pump}$ was calculated as follows:

$$L_{Div1\ Pump} = (L_{One\ Pump} * P_{1\text{-}1}) + (L_{Three\ Pumps} * P_{1\text{-}3})$$

$$= (6.78 \times 10^{-7}/hr * 0.5) + (1.34 \times 10^{-7}/hr * 0.5)$$

$$= 4.06 \times 10^{-7}/hr$$

The analyst assumed that a fire damaged pump would remain inoperable for the 30-day allowed-outage time. Therefore, the probability that the redundant Division I pump would start and run for 30 days, $P_{Alt\ Fails}$, was calculated as follows:

$P_{Alt\ Fails} = P_{FTS} * P_{run-1} + L_{FTR}$

$= (3.0 \times 10^{-3} * 0.5) + (3.0 \times 10^{-5}/hr * 24\ hrs/day * 30\ days)$

$= 1.5 \times 10^{-3} + 2.16 \times 10^{-2}$

$= 2.31 \times 10^{-2}$

The likelihood of having a loss of all SW as a result of a one-pump fire, $L_{pump\ LOSWS}$, is then calculated as follows:

$L_{pump\ LOSWS} = L_{Div1\ Pump} * P_{Alt\ Fails}$

$= 4.06 \times 10^{-7}/hr * 2.31 \times 10^{-2}$

$= 9.38 \times 10^{-9}/hr$

The likelihood of both pumps in Division 1 being damaged because of a fire ($L_{Div1\ Pumps}$) was calculated as follows:

$L_{Div1\ Pumps} = L_{Three\ Pumps} * P_{2-3}$

$= 1.34 \times 10^{-7}/hr * 0.5$

$= 6.7 \times 10^{-8}/hr$

Given that a fire-induced loss of both Division I pumps results in a TSW system gland water and the assumption was made that the gland water was unrecoverable during large fire scenarios, $L_{Div1\ Pumps}$ is equal to the likelihood of a TSW system initiating event.

The analyst used the revised baseline and current case SPAR models to quantify the conditional core damage probability (CCDP) for a fire that takes out both Division I pumps or one Division I pump with a failure of the second pump. A fire that affects both Division I pumps was assumed to cause an unrecoverable TSW initiating event. The baseline CCDP was determined to be 1.99×10^{-8}. The current case probability was 6.63×10^{-4}. Therefore, the ΔCDP was 6.63×10^{-4}.

The analyst also assessed the effect of this finding on a postulated fire in Switchgear 1F. The analyst walked down the switchgear rooms and interviewed licensed operators. The analyst identified that, by procedure, a fire in Switchgear 1F would require deenergization of the bus and subsequent manual scram of the plant. Additionally, the analyst noted that no automatic fire suppression existed in the room. Therefore, the analyst used the fire ignition frequency stated in the IPEEE, namely 3.70×10^{-3}/yr ($L_{switchgear}$), as the frequency for loss of Switchgear 1F and a transient.

The analyst used the revised baseline and current case SPAR models to quantify the CCDPs for a fire in Switchgear 1F. The resulting CCDPs were 1.88×10^{-4} ($CCDP_{base}$) for the baseline and 1.70×10^{-2} ($CCDP_{current}$) for the current case. The change in CDF was calculated as follows:

$\Delta CDF = L_{switchgear} * (CCDP_{current} - CCDP_{base})$

$= 3.70 \times 10^{-3}/yr \div 8760\ hrs/yr * (1.70 \times 10^{-2} - 1.88 \times 10^{-4})$

$= 7.10 \times 10^{-9}/hr$

Table 4.b: Internal Fire Risk				
Fire Areas:	Fire Type	Fire Ignition Frequency	ΔCDP	ΔCDF
Switchgear 1F	Shorts Bus	4.22×10^{-7}/hr	1.68×10^{-2}	7.10×10^{-9}/hr
Service Water Pump Room	One Pump	9.38×10^{-9}/hr	6.63×10^{-4}	6.22×10^{-12}/hr
	Both Pumps	6.7×10^{-8}/hr	6.63×10^{-4}	4.44×10^{-11}/hr
Total ΔCDF for Fires affecting the Service Water System:				7.14×10^{-9}/hr
Exposure Time (21 days):				5.04×10^{2} hrs
External Events Change in CDF:				3.60×10^{-6}

3) <u>Potential Risk Contribution from LERF</u>:

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, step 2.6, "Screening for the Potential Risk Contribution Due to LERF," the analyst assessed the impact of large early release frequency because the Phase 2 significance determination process result provided a risk significance estimation of 7.

In BWR Mark I containments, only a subset of core damage accidents can lead to large, unmitigated releases from containment that have the potential to cause prompt fatalities prior to population evacuation. Core damage sequences of particular concern for Mark I containments are intersystem loss of coolant accidents (ISLOCAs), anticipated transients without scram (ATWS), station blackouts (SBO), and small-break loss of coolant accident (SBLOCA)/transient sequences involving high reactor coolant system pressure. A TSW is a special initiator for a transient. Step 2.6 of Manual Chapter 0609 requires a LERF evaluation for all reactor types if the risk significance estimation is 7 or less and transient sequences are involved.

In accordance with Manual Chapter 0609, Appendix H, "Containment Integrity SDP," the analyst determined that this was a Type A finding, because the finding affected the plant CDF. The analyst evaluated both the baseline model and the current case model to determine the LERF potential sequences and segregate them into the categories provided in Appendix H, Table 5.2, “Phase 2 Assessment Factors - Type A Findings at Full Power. The primary distinctions in categories are based on the initiator type, the pressure of the reactor coolant system at the time of core damage, and whether the drywell floor has been flooded, either by the event or by operator action. The type of event is indicative of the mode of core damage and the available systems, the coolant system pressure indicates whether the core will melt through or be ejected from the vessel, and in a Mark I containment, the steel line is significantly more susceptible to melt through if there is no water on the drywell floor. The categories, the total CDF related to each of these categorizations, the LERF factors, and an estimation of the change in LERF are documented in Table 5 of this worksheet.

Following each model run, the analyst segregated the core damage sequences as follows:

- Loss of coolant accidents were assumed to result in a wet drywell floor. The analyst assumed that during all station blackout initiating events the drywell floor remained dry. The Cooper Nuclear Station emergency operating procedures require drywell flooding if reactor vessel level cannot be restored. Therefore, the analysts assumed that containment flooding was successful for all high pressure transients and those low pressure transients that had the residual heat removal system available.

- All individual intersystem loss of coolant accident initiators designated in the SPAR model were grouped in the ISLOCA category.

- Transient Sequence 65, Loss of dc Sequence 62, TSW system Sequence 71, small loss of coolant accident Sequence 41, medium loss of coolant accident Sequence 32, large loss of coolant accident Sequence 12, and LOOP Sequence 40 cutsets were considered ATWS sequences.

- All LOOP Sequence 39 cutsets were considered SBOs. Those with success of safety-relief valves to close or a single stuck-open relief valve were considered high pressure sequences. Those with more than one stuck-open relief valve were considered low pressure sequences.

- Transients that did not result in an ATWS were assumed to be low pressure sequences if the cutsets included low pressure injection, core spray, or more than one stuck-open relief valve. Otherwise, the analyst assumed that the sequences were high pressure.

- SBLOCA Sequence 1 cutsets, that represent stuck-open relief valves and other recoverable incidents, were assumed to result in a dry floor. All other cutsets were assumed to provide a wetted drywell floor.

The resulting ΔLERF for internal events was 6.31 x 10^{-6}, as documented in Table 5. Additionally, the analyst used the internal events LERF ratios to estimate the external events contribution to LERF. As documented in Table 3.a, the external events ΔLERF was calculated as 3.2 x 10^{-6}. This resulted in a total ΔLERF for the finding of 9.5 x 10^{-6}.

Table 5: Large Early Release Frequency

Event	Drywell Floor	Current Case	Baseline	LERF Factor	ΔLERF
ISLOCA		4.70e-13	4.70e-13	1.0	0.00e+00
ATWS		3.26e-11	3.14e-11	0.3	3.60e-13
SBO High	Wet	0.00e+00	0.00e+00	0.6	0.00e+00
	Dry	1.57e-08	3.51e-09	1.0	1.22e-08
SBO Low	Wet	0.00e+00	0.00e+00	0.1	0.00e+00
	Dry	3.21e-10	5.99e-11	1.0	2.61e-10
Transient High	Wet	1.00e-09	8.87e-10	0.6	6.78e-11
	Dry	0.00e+00	0.00e+00	1.0	0.00e+00
Transient Low	Wet	1.78e-11	1.16e-11	0.1	6.20e-13
	Dry	3.20e-10	3.17e-10	1.0	3.00e-12

(continued) Event	Drywell Floor	Current Case	Baseline	LERF Factor	ΔLERF
SBLOCA	Wet	1.82e-12	7.93e-13	0.6	6.16e-13
	Dry	2.32e-12	1.96e-13	1.0	2.12e-12
MBLOCA	Wet	1.43e-12	1.21e-12	0.1	2.17e-14
	Dry	0.00e+00	0.00e+00	1.0	0.00e+00
LBLOCA	Wet	3.74e-12	3.59e-12	0.1	1.51e-14
	Dry	0.00e+00	0.00e+00	1.0	0.00e+00
Total ΔCDF per hour		1.74e-08	4.82e-09		1.26e-08
Total ΔLERF per Hour		1.70e-08	4.43e-09		1.25e-08
Exposure Time (21 days)					5.04e+02
Total ΔLERF					6.31e-06

(d) Licensee's Risk Assessment:

The licensee performed an assessment of the risk from this finding as documented in Engineering Study PSA-ES062, "Risk Significance of SCR 2004-0077, Service Water Gland Water Valve Mis-positioning Event." The licensee's result for internal risk was a ΔCDF of 3.85×10^{-7}. The analyst reviewed the licensee's assumptions and determined that the following differences dominated the difference between the licensee's and the analyst's assessments (presented in order of risk significance):

- As stated in Assumption i) in the above analysis, the analyst used a value of 0.4 for the probability that operators would fail to realign gland water prior to failure of the Division II pumps. This value was derived using the INEEL's SPAR-H method. The licensee used a Human Error Probability of 9.2×10^{-2}, derived using an Electric Power Research Institute calculator.

  The analyst determined that this assumption was responsible for about 30 percent of the difference in the final results.

- The licensee's model uses a LOOP frequency of 1.74×10^{-8}/hr as opposed to the analyst's use of the NUREG/CR-5496 value of 5.32×10^{-6}/hr.

  The analyst determined that this assumption was responsible for the vast majority of the difference in the final results. The analyst noted that the majority of risk was from core damage sequences that were initiated by a LOOP.

Additionally, the following differences between the licensee's and the analyst's evaluations were identified:

- The analyst utilized generic industry probabilities for emergency diesel generator failures to start, failures to run, and the emergency diesel generator availability. The licensee's model uses Cooper Nuclear Station specific historical probabilities that are lower.

- The analyst utilized functional impact frequency values from NUREG/CR-5750, Table D-11, for the likelihood of full and partial TSW events. The licensee used significantly lower values derived from a plant-specific system model that was dominated by common cause failure of the pumps.

- The analyst used the SPAR assumptions that core damage would occur if the batteries depleted following an SBO. The licensee used the MAPP code to determine the point in time that the fuel was assumed to reach a temperature of 1800°F.

- The analyst assumed that all fires in Switchgear 1F would result in an unrecoverable deenergization of the switchgear. The licensee stated that certain fire scenarios would be recoverable.

- The analyst used the SPAR model as modified to calculate the ΔCDF, while the licensee used their plant-specific probabilistic risk assessment model.

- The analyst used Inspection Manual Chapter 0609, Appendix H methodology to estimate the ΔLERF. The licensee utilized their plant specific Level 2 model to identify the LERF multipliers used.

(e) <u>Sensitivity Studies</u>:

The analyst performed sensitivity studies on several major assumptions using the internal events SPAR model. Table 6 summarizes the assumptions and the results. The analyst determined that using the licensee's value for LOOP frequency would change the characterization of this finding significantly. However, the agency has determined that the values in NUREG/CR-5496 are the best available data. Additionally, large changes to the recovery of gland water value could impact the characterization of this finding.

Table 6: Sensitivity Studies			
Parameter	Initial Value	New Value	New Result
IE-LOOP	1.74×10^{-8}/hr	5.32×10^{-6}/hr	1.8×10^{-7}
Adjusted IE-LOSWS	6.2×10^{-7}/hr	6.2×10^{-8}/hr	6.4×10^{-6}
Gland Recovery	0.4	0.1	2.0×10^{-6}

(4) Enforcement. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states 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. Contrary to this requirement, Clearance Order SWB-1-4324147 SW-STNR-B did not provide adequate instructions to restore the SW system to an operable configuration following the completion of maintenance activities on January 21, 2004. This resulted in Division 2 of the SW system being inoperable from January 21 through February 11, 2004. This violation of 10 CFR Part 50, Appendix B, Criterion V, is identified as an apparent violation (AV 05000298/2004014-01) pending determination of the finding's final safety significance.

4OA6 Meetings, Including Exit

On July 22, 2004, the inspectors presented the results of the resident inspector activities to J. Roberts, Director of Nuclear Safety Assurance, and other members of his staff who acknowledged the finding.

The inspectors confirmed that proprietary information was not provided by the licensee during this inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

J. Bednar, Emergency Preparedness Manager
C. Blair, Engineer, Licensing
M. Boyce, Corrective Action & Assessments Manager
J. Christensen, Director, Nuclear Safety Assurance
S. Minahan, General Manager of Plant Operations
T. Chard, Radiological Manager
K. Chambliss, Operations Manager
K. Dalhberg, General Manager of Support
J. Edom, Risk Management
R. Estrada, Performance Analysis Department Manager
M. Faulkner, Security Manager
J. Flaherty, Site Regulatory Liaison
P. Fleming, Licensing Manager
W. Macecevic, Work Control Manager
D. Knox, Maintenance Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000298/2004014-01	AV	Inadequate instructions for restoration of the SW system following maintenance (Section 1R04)