RH-6D5

(5)

Analysis:

A. Brief Description of Issue

On January 21, 2004, the Division II service water discharge strainer was bypassed for routine maintenance (cleaning). In accordance with operating procedures, the gland water supply for the Division II pumps was cross-connected with the Division I pumps. This is performed to prevent the introduction of large debris into the Division II pump glands. At that time, licensed operators declared the Division II service water subsystem to be inoperable because it was no longer independent from the other division, as required. Following maintenance, the discharge strainer was returned to service, and the Division II service water subsystem was declared operable. However, operators restoring the system, failed to realign the gland water supply to the Division II pumps. Therefore, the interdependence between the two divisions remained.

On February 11, licensed operators were conducting a valve alignment verification because several spurious gland water low pressure annunciators had alarmed for Division II pumps. The incorrect alignment was discovered as a result. Licensed operators appropriately declared Division II inoperable. The valves were realigned and the system was restored to an operable status.

B. Statement of Performance Deficiency

The licensee failed to provide appropriate procedural guidance to operators for the restoration of the Division II service water pump gland water supply following maintenance and prior to returning the system to service. As a result, Division II service water gland sealing water continued to be provided by the Division I service water pumps. In this configuration, a failure of the Division I pumps would result in loss of gland water to the Division II pumps.

C. Significance Determination Basis

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 was estimated to be 1.0×10^{-5} and the total change in large early release frequency was estimated to be 9.5×10^{-6}. The assumptions and considerations used in the evaluation are presented as follows:

1. Phase 1 Screening Logic, Results and Assumptions

In accordance with NRC Inspection Manual Chapter 0612, Appendix B, "Issue Screening," the inspectors determined that the failure of the licensee to provide appropriate procedural guidance to operators for the restoration of the Division II service water pump gland water supply following maintenance and prior to returning the system to service was a licensee performance deficiency. Additionally, the failure to properly align the gland water system was fully within the licensee's ability to control. The issue was more than minor because it was similar to Example 4.e in Manual Chapter 0612, Appendix E, "Examples of Minor

DD-17

Issues," and it met the "not minor if" criteria, in that the error resulted in improper valve manipulation (alignment).

The inspectors evaluated the issue using the 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 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. Therefore, the issue was passed to Phase 2.

2. <u>Phase 2 Estimation for Internal Events</u>

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 a service water pump will result in the failure of the pump to meet its risk-significant function.
- The configuration of the service water system increased the likelihood that all service water would be lost.
- The condition existed for 21 days. Therefore, the exposure time window used was 3 - 30 days.
- The initiating event likelihood credit for loss of service water 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 loss of service water, a normally cross-tied support system.
- The configuration of the service water 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 service water system would continue to be a multi-train system.
- Because both divisions of service water 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 service water mitigating function were not included in the analysis.

The last two assumptions are a deviation from the risk-informed notebook that was recommended by the Senior Reactor Analyst. 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 service water system. However, given the assumption that the service water system function was not degraded, only the sequences with the special initiator for Loss of Service Water (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 Service Water	1	RECSW24-LI	6
Loss of Service Water	2	RCIC-LI	6
Loss of Service Water	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 overly conservative and/or did not represent the actual configuration of the system, a Phase 3 evaluation is required.

3. Phase 3 Analysis

<u>Internal Initiating Events</u>

<u>Assumptions</u>:

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 service water divisions, as well as an assessment of the licensee's evaluation provided by the licensee's probabilistic risk assessment staff. The SPAR runs were based on the following analyst assumptions:

a. The Cooper SPAR model was revised to better reflect the failure logic for the service water 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 service water 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 25 through February 11, 2004 representing the exposure time.

e. The nominal likelihood for a loss of service water, $IEL_{(TSW)}$, 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 service water frequency at 9.72×10^{-4} per critical year.

f. The nominal likelihood for a partial loss of service water, $IEL_{(PTSW)}$, 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 service water frequency (loss of single division) at 8.92×10^{-3} per critical year.

g. The configuration of the service water system increased the likelihood that all service water would be lost. The increase in loss of service water 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 service water 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 service water.

i. The probability of operators failing to properly diagnose the need to restore Division II service water gland water upon a loss of Division I service water 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 service water. The analyst noted that this walk through did not require operators to prioritize many different annunciators. Additionally, operations personnel had been briefed on the finding at a time prior to the walk through, 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 service water 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 service water 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.

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

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

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

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

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

<u>Evaluation of Change in Risk</u>: Using Assumptions a and b, the analyst modified Revision 3.03 of the SPAR model to include updated loss of offsite power curves as published in NUREG CR-5496. The changes to the loss of offsite power 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 service water 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 core damage frequency, CDF_{base}, was 4.82×10^{-9} /hr.

The analyst changed this modified model to reflect that the failure of the Division I service water 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 core damage frequency, CDF_{case}, of 1.74×10^{-8} /hr.

The change in core damage frequency (ΔCDF) from the model was:

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

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

$\Delta CDF = 1.26 \times 10^{-8}$ /hr * 24 hr/day * 21 days = 6.35×10^{-6} 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 ACP 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 Hours	1.2×10^{-1}	3.93×10^{-1}
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 in accordance with NUREG/CR-5496			

Table 3.a: Phase 3 Analysis Results

Model	Result	Core Damage Frequency	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: The analyst assumed that the ratio of high and low pressure sequences were the same as for internal events baseline.

Table 3.b: Top Risk Cutsets

Initiating Event	Sequence Number	Sequence	Importance
Loss of Offsite Power	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}
	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 Service Water System	9	PC1-SPC-SDC-CSS-CR1-VA1	2.2×10^{-11}

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.

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

The analyst determined, through plant walkdown, that the major divisional equipment associated with the service water system were on the same physical elevation as its redundant equipment in the alternate division. All four service water 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.

Fire:

The analyst evaluated the list of fire areas documented in the licensee's fire plan, and concluded that the Division I service water 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 service water 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 service water 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 Service Water Pump	L_{FTR}	3.0×10^{-5}/hr
Failure to Start Probability per Demand for a Service Water 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 service water pump room, namely: a fire damaging one pump, caused by a small oil fire, a fire that results from the spill of all the oil from a single pump that damages three pumps; and fires that affect all four pumps. The licensee had determined that fires affecting only two pumps were not likely. 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 loss of service water 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. It should be noted that the intensity of an oil fire is based on the availability of oxygen, and the fire is assumed to continue until all oil is consumed or it is 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 actuate, or if the fire lasted for 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:

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

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

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

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

The likelihood of having a loss of all service water 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:

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

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

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

Given that a fire-induced loss of both Division I pumps results in a loss of service water 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 loss of service water system initiating event.

The analyst used the revised baseline and current case SPAR models to quantify the conditional core damage probability 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 loss of service water initiating event. The baseline conditional core damage probability 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 affect 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 conditional core damage probabilities for a fire in Switchgear 1F. The resulting CCDPs were 1.88×10^{-4} ($CCDP_{base}$) for the baseline and 1.70×10^{-2} ($CCDP_{current}$). The change in core damage frequency 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 Core Damage Frequency:				3.60×10^{-6}

<u>Potential Risk Contribution from Large Early Release Frequency (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 SDP 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 (ISLOCA), 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 loss of service water (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 core damage frequency. 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. [redacted] Ex 5

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 emergency operating procedures require drywell flooding if reactor vessel level can not 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 Event V initiators were grouped as ISLOCA

- Transient Sequence 65, Loss of dc Sequence 62, Loss of service water 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 loss of offsite power (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.

[redacted]

Ex5

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):

1. The analyst used a failure probability of 0.4, derived from the INEEL's SPAR-H method. The licensee used a Human Error Probability of 9.2×10^{-2} for the probability that operators would fail to realign gland water prior to failure of the Division II pumps. The analyst used a failure probability of 0.4, derived from the INEEL's SPAR-H method.

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

2. The licensee's model uses a Loss of Offsite power frequency of 1.74×10^{-8}/hr as opposed 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 loss of offsite power.

Additionally, the following differences between the licensee's and the analysts 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 loss of service water 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° Fahrenheit.

- 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.

[redacted]

Ex 5