FOIA/PA NO: ______2013-0250_____

GROUP D

RECORDS BEING RELEASED IN PART

The following types of information are being withheld:

Ex. 1: ☐ Records properly classified pursuant to Executive Order 12,958
Ex. 2: ☐ Records regarding personnel rules and/or human capital administration
Ex. 3: ☐ Information about the design, manufacture, or utilization of nuclear weapons
☐ Information about the protection or security of reactors and nuclear materials
☐ Contractor proposals not incorporated into a final contract with the NRC
☐ Other____
Ex. 4: ☐ Proprietary information provided by a submitter to the NRC
☐ Other____
Ex. 5: ☑ Draft documents or other pre-decisional deliberative documents (D.P. Privilege)
☐ Records prepared by counsel in anticipation of litigation (A.W.P. Privilege)
☐ Privileged communications between counsel and a client (A.C. Privilege)
☐ Other____
Ex. 6: ☑ Agency employee PII, including SSN, contact information, birthdates, etc.
☑ Third party PII, including names, phone numbers, or other personal information
Ex. 7(A): ☐ Copies of ongoing investigation case files, exhibits, notes, ROI's, etc.
☐ Records that reference or are related to a separate ongoing investigation(s)
Ex. 7(C): ☐ Special Agent or other law enforcement PII
☐ PII of third parties referenced in records compiled for law enforcement purposes
Ex. 7(D): ☐ Witnesses' and Allegers' PII in law enforcement records
☐ Confidential Informant or law enforcement information provided by other entity
Ex. 7(E): ☐ Law Enforcement Technique/Procedure used for criminal investigations
☐ Technique or procedure used for security or prevention of criminal activity
Ex. 7(F): ☐ Information that could aid a terrorist or compromise security

Other/Comments:____
____

Hills, David

From: Sanchez Santiago, Elba
Sent: Friday, May 03, 2013 2:14 PM
To: Orth, Steven
Cc: Hills, David
Subject: Palisades Report
Attachments: Palisades Input to DRP Report 2013 002 URI EMS.docx

Importance: High

Steve,

Attached is the latest draft of the report. I incorporated some of the comments you made and made some changes to address others. You will notice there is still some mention of the corrective actions taken in 2001 in the write-up for the Proposed Criterion V. The reason for this is to address the arguments presented by the licensee in the white paper they provided us. I also included a paragraph that more clearly states what the differences between 2001 and 2012 are.

With regards to some of your comments related to the Criterion XVI issue, specifically the comment on corrective action, the list provided in the write-up is to provide a comparison of the information available at the time and different actions taken as they relate to weld #5. It is not meant to represent the proposed corrective actions to prevent recurrence. I made some changes to more clearly state this in a separate paragraph.

Feel free to contact me with questions or comments. I can be reached today at the office (630-829-9715). If you are reviewing the report at a later time, feel free to call me to help resolve any questions or concerns you may have. I can be reached at (b)(6) Ex 6 WIP

Thanks,

Elba M. Sanchez Santiago
Reactor Engineer
RIII/ DRS/ EB1
630-829-9715

D 1

UNITED STATES
NUCLEAR REGULATORY COMMISSION
LISLE, IL 60532-4352

May XX, 2012

MEMORANDUM TO: Thomas Taylor
Senior Resident Inspector
Palisades Nuclear Plant

FROM: David Hills, Chief
Engineering Branch 3
Division of Reactor Safety

SUBJECT: PALISADES NUCLEAR PLANT
DRS INPUT TO INTEGRATED REPORT 05000255/2013002

Enclosed is the report input for the Palisades Nuclear Plant, Inspection Report 05000255/2013002. This report input documents completion of our review of Unresolved Items 05000255/2012012-01, "TS for PCS Pressure Boundary Leakage," 05000255/2012012-02, "Potential Inadequate Degradation Evaluation of CRDM Housings," and 05000255/2012012-03, "Potential Failure to Prevent Recurrence of a Significant Condition Adverse to Quality." This report also completes one sample of the Problem Identification and Resolution, Selected Issue Follow-up inspection in accordance with IP 71152. I have reviewed this input to confirm compliance with Inspection Manual Chapter (IMC) 0612 and IMC 0305. This input is ready for inclusion into the integrated report and dissemination to the public.

Please input the following post Inspection Data into RPS:

Inspection Procedure	**Procedure Status** – see below: Incomplete, Complete, Complete by reference, Complete-full sample not available, Complete – opportunity to apply procedure not available, Not Applicable.	**Sample Size** – As documented in Scope Section If less than full sample size documented in the report input, the inspector must provide a justification below to enter into RPS and support the procedure status selected
71152	Complete	1

Inspection Report Item and Type (AV, FIN, NCV, URI or VIO)	**Cornerstone** (IE, MS, BI, EP, OR, PR, MISC)	**Cross Cutting Aspect** (H.n(i), P.n(i), S.n(i))	**Responsible Person/Owner**	**Procedure or TI** (71111.07T)	**RPS Branch Code (e.g. closeout responsibility)** EB1 3820 EB2 3870 EB3 3840 PST (RP) 3860 PSB (Safeguards) 3850 OB 3810
NCV-XXX	IE	n/a	E. Sanchez Santiago	71152	3820
NCV-XXX	IE	H.1(b)	E. Sanchez Santiago	71152	3820

D2

Enclosure: Input to Inspection Report 05000255/2013002

cc w/encl: J. Giessner, Chief
C. Hernandez, Site Admin Assistant

CONTACT: E. Sanchez Santiago, DRS
(630) 829-9715

DOCUMENT NAME: G:\DRSIII\DRS\Work in Progress\-Palisades Input to DRP Report 2013 002 URI EMS.docx
□ Publicly Available □ Non-Publicly Available □ Sensitive □ Non-Sensitive
To receive a copy of this document, indicate in the box: "C" = Copy without attachment/enclosure "E" = Copy with attachment/enclosure "N" = No copy

OFFICE	RIII		NRR		RIII		NRR	
NAME	ESanchezSantiago		DAlley		DHills		TLupold	
DATE	5/ /13							

OFFICIAL RECORD COPY

Cover Letter

X Green findings involving a violation were identified. Include the following:

Based on the results of this inspection, two NRC-identified findings of very low safety significance (Green) were identified. These findings were determined to involve a violation of NRC requirements. However, because of the very low safety significance and because the issues were entered into your corrective action program, the NRC is treating the issue as Non-Cited Violation, in accordance with Section 2.3.2 of the NRC Enforcement Policy.

TITLE PAGE

Inspectors: D. Alley, Senior Materials Engineer
E. Sanchez Santiago, Reactor Inspector

SUMMARY OF FINDINGS

A. NRC-Identified and Self-Revealed Findings

Cornerstones: Initiating Events

- Green. A self-revealing Green Finding with associated Non-Cited Violations (NCV) of 10 CFR Part 50, Appendix B, Criterion XVI and Technical Specification (TS) 3.4.13 Primary Coolant System (PCS) Operational Leakage, was identified for failure to take corrective actions to prevent recurrence of Control Rod Drive Mechanism (CRDM) cracking and leakage, a significant condition adverse to quality (SCAQ), and resulting in operation of the reactor with reactor coolant system pressure boundary leakage. Specifically, for Criterion XVI the licensee failed to include the internal CRDM housing weld build-up area within the scope of corrective actions taken for a 2001 CRDM through wall leak on CRDM-21 caused by transgranular stress corrosion cracking (TGSCC). Subsequently, a through wall leak recurred in the weld build-up area on CRDM-24 in 2012 due to TGSCC. As a result, the licensee operated with PCS pressure boundary leakage which is not allowed by TS 3.4.13. Further, because the licensee was not aware that the leakage was PCS pressure boundary leakage, the licensee did not implement the associated TS action statement. The licensee replaced CRDM-24 upper housing and wrote CR-PLP-01134.

  The inspectors determined that this issue was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because it adversely affected the Initiating Events Cornerstone objective to limit the likelihood of events that upset plant stability. The issue was associated with the attribute of equipment performance. Specifically, the licensee did not take adequate corrective actions to prevent recurrence of leakage in CRDM housings which represents pressure boundary leakage. In accordance with Table 2 "Cornerstones Affected by Degraded Condition or Programmatic Weakness" of IMC 609, Attachment 4 "Initial Characterization of Findings" issued June 19, 2012, the inspectors checked the box under the Initiating Events Cornerstone because the failure of a CRDM housing is a Primary System Loss of Coolant Accident (LOCA) initiator contributor. The inspectors determined this finding

was of very low safety significance (Green) based on answering "no" to the Exhibit 1 "Initiating Events Screening Questions," in IMC 0609 Attachment A "The Significance Determination Process (SDP) for Findings At-Power" issued on June 19, 2012. Specifically, the inspectors answered "no" to the screening question associated with exceeding the reactor coolant system leak rate for a small LOCA and "no" to the question associated with whether the finding could have likely affected other systems used to mitigate a LOCA resulting in a total loss of their function. The inspectors answered no to these questions because of the slow rate of change for leakage for this cracking mechanism and this type of material. Type 316 stainless steel material under TGSCC will experience leakage rates well below a small break LOCA which would be observed through the crack, alerting operators to take action to shut down the plant prior to experiencing a component rupture. The cause of this finding, non-conservative decision making occurred over ten years ago and is well outside of the nominal 3 year period in IMC 0612; and would not be indicative of current performance, unless there were other opportunities to identify the issue; therefore, the inspectors concluded this was not indicative of current performance. However more recently, the licensee exhibited non-conservative decision making with respect to addressing the potential for CRDM housing cracking and leakage during the recent root cause (Section 4OA2.3 (b.2) of this report), resulting in another finding. This cross-cutting aspect will be captured through the other finding. (Section 4OA2.3(b.1))

- Green. The inspectors identified a Finding with an associated NCV of 10 CFR Part 50, Appendix B, Criterion V, for the licensee's failure to accomplish quality activities in accordance with the prescribed procedures. Specifically, the licensee failed to adequately evaluate and document the generic implications of the cause of the cracking identified in CRDM-24 in accordance with root cause procedure EN-LI-118. This issue was entered into the licensee's corrective action program under CR-PLP-2013-01500.

  The inspectors determined that this issue was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because the inspectors answered "yes" to the More-than-Minor screening question "if left uncorrected, would the performance deficiency have the potential to lead to a more significant safety concern?" Specifically, absent NRC identification, the licensee would not have completed further evaluations or inspections of CRDM housing welds which could have resulted in additional CRDM housing failure and leakage by TGSCC. In accordance with Table 2 "Cornerstones Affected by Degraded Condition or Programmatic Weakness" of IMC 609, Attachment 4 "Initial Characterization of Findings" issued June 19, 2012, the inspectors checked the box under the Initiating Events Cornerstone because the failure of a CRDM housing is a Primary System LOCA initiator contributor. The inspectors determined this finding was of very low safety significance (Green) based on answering "no" to the Exhibit 1 "Initiating Events Screening Questions," in IMC 0609, Attachment A "The Significance Determination Process (SDP) for Findings At-Power" issued on June 19, 2012. Specifically, the inspectors answered "no" to the screening question associated with exceeding the reactor coolant system leak rate for a small LOCA and "no" to the question associated with whether the finding could have likely affected other systems used to mitigate a LOCA resulting in a total loss of their function. The inspectors answered no to these questions because of the slow rate of change for leakage for this cracking mechanism and this type of material. Type 316 stainless steel material under TGSCC will experience leakage rates well below a small break LOCA which would be observed through the crack, alerting operators to take action to shut down the plant prior to

experiencing a component rupture. The inspectors determined that the primary cause of the failure to adequately consider welds No. 3 and No. 4 in the generic implications section of the root cause report (RCR) related to the cross-cutting component of Human Performance, Decision Making, because licensee staff did not use conservative assumptions in decision making. Specifically, the licensee did not use conservative assumptions when excluding welds No. 3 and No. 4 as being susceptible to TGSCC when there was not enough information to exclude them from consideration. (Item H.1(b)). (Section 4OA2.3(b.2))

B. Licensee-Identified Violations

No violations of significance were identified.

REPORT DETAILS

4. REACTOR SAFETY

4OA2 Identification and Resolution of Problems (71152)

.3 Selected Issue Follow-up Inspection: Through Wall Leakage of CRDM-24 (This inspection is part of the additional inspections included in the Palisades Deviation letter)

a. Inspection Scope

On August 12, 2012, the licensee shut down the plant to investigate an increase in unidentified leakage. The source of the leakage was determined to be a crack in CRDM-24. The NRC dispatched a special inspection team (SIT) to review the CRDM-24 leakage event. The results of that inspection are provided in Inspection Report 05000255/2012012. The licensee completed an evaluation to determine the cause of the cracking (CR-PLP-2012-05623).

From March 4, 2013 to March 15, 2013, the inspectors completed one inspection sample regarding problem identification and resolution based upon review of the licensee's RCR contained in corrective action document CR-PLP-2012-05623. In addition the inspectors performed reviews related to three Unresolved Items (URI) identified during the SIT inspection:

- URI 05000255/2012012-01 TS for PCS Pressure Boundary Leakage. (The closure of this URI is documented in section 4OA2.3 (b.1) of this report.)
- URI 05000255/2012012-02 Potential Inadequate Degradation Evaluation of CRDM Housings (The closure of this URI is documented in section 4OA5.1 of this report)
- URI 05000255/2012012-03 Potential Failure to Prevent Recurrence of a Significant Condition Adverse to Quality (The closure of this URI is documented in section 4OA2.3 (b.1) of this report.)

The inspectors reviewed the licensee's actions in accordance with performance attributes identified in IP 71152. Specifically, the inspectors reviewed licensee corrective action records to determine if: (1) the problems were accurately identified; (2) operability and reportability were adequately ascertained; (3) extent of condition and generic implications were appropriately addressed; (4) classification and prioritization of the problem were commensurate with safety significance; (5) root and contributing causes were identified; (6) corrective actions were appropriately focused to correct the problem; and (7) timely corrective actions were completed or proposed commensurate with the safety significance of the issues.

b. Findings

.1 Failure to Take Corrective Actions to Prevent Recurrence of CRDM Housing Cracking and Leakage

Introduction: A self-revealing Green Finding with associated NCV of 10 CFR Part 50, Appendix B, Criterion XVI and TS 3.4.13 PCS Operational Leakage, was identified for failure to take corrective actions to prevent recurrence of CRDM cracking and leakage, a SCAQ, and resulting in operation of the reactor with PCS pressure boundary leakage. Specifically, for Criterion XVI the licensee failed to include the internal CRDM housing weld build-up area within the scope of corrective actions taken for a 2001 CRDM through wall leak on CRDM-21 caused by TGSCC. Subsequently, a through wall leak recurred in the weld build-up area on CRDM-24 in 2012 due to TGSCC. As a result, the licensee operated with PCS pressure boundary leakage which is not allowed by TS 3.4.13. Further, because the licensee was not aware that the leakage was PCS pressure boundary leakage, the licensee did not implement the associated TS action statement.

Description: In 2001, the licensee discovered a steam leak in the housing of CRDM-21 caused by a through-wall TGSCC at CRDM housing weld No. 3 which was located just below the weld build-up region (weld No. 5). Weld No. 5 consists of a weld material deposit applied to the inside diameter (ID) of the CRDM housing which provides for alignment of the CRDM. This issue was categorized as a SCAQ by the licensee (CPAL0102186) because it represented a break in the reactor system pressure boundary. The licensee's root cause evaluation was documented in RCR/C-PAL-01-02186 and concluded that the cracks in CRDM-21 were caused by TGSCC which occurred in areas of heavy grinding or machining tool marks. Specifically, this leak was the result of an ID initiated, axially oriented, transgranular crack in the austenitic stainless steel housing material. The failure analysis performed in response to this event identified both axial and circumferential cracks associated with weld No. 3. Extent of condition inspections revealed additional, non-through wall cracks associated with weld No. 3 in 41 of the 44 remaining housings for a total of 42 of 45 housings containing cracks.

In response to the 2001 cracking, Palisades replaced all 45 CRDM housings with housings thought to be more resistant to cracking. Principle changes included:

- Elimination of weld No. 2,
- Relocation of weld No. 3 to a higher location thereby minimizing the deposition of crud in the gap between the weld and the bottom plate of the rack and pinion assembly,
- Reduction in residual stresses and cold work on welds by requiring better surface finishes, and
- Use of heat sink welding to reduce ID residual tensile stresses.

In January of 2002, an NRC SIT (reference IR 50-2555/01-15) reviewed the licensee proposed corrective actions associated with the through-wall leakage of the CRDM-21 housing caused by TGSCC. The 2001 RCR reviewed by the NRC stated the action to prevent recurrence was to "develop and implement an inspection plan to address areas and components identified in Attachment C-Extent of Condition. One of the components included in Attachment C was the CRDM. The recommended action was to perform volumetric inspection of the welds contained in the CRDM. Subsequently, the licensee changed the corrective actions and excluded weld No. 5.

Following the subsequent 2012 CRDM-24 leak, the licensee determined the leak occurred because of a through-wall crack adjacent to weld No. 5. The licensee formed a root cause team (RCT) staffed with licensee personnel and augmented with input from vendors. The root cause investigation was conducted in accordance with site procedure EN-LI-118 "Root Cause Evaluation Process" and was documented in root cause analysis report CR-PLP-2012-05623. In this report, the licensee's RCT determined that the probable cause of the cracking was:

> "Stresses in the weld build up area due to manufacturing irregularities and misalignments between CRDM-24 upper housing, support tube, and the associated reactor head penetration/CRDM nozzle. Based on lack of cracking found in the other eight upper housings tested, the failed CRDM-24 upper housing contains an as-yet unidentified additional stress."

The RCT also identified the following contributing cause:

> "TGSCC initiating within the internal weld build-up material of CRDM-24. The through wall crack initiated in the weld material and then propagated through the base metal until a leak developed in the outer diameter (OD) witness band region at the base of the ID weld build up.

This conclusion was based upon destructive and non destructive examinations (NDE) completed on a section of the failed housing which included the through-wall flaw. The RCT also relied upon vendor technical reports assessing the results of the NDE as well as vendor calculations related to the stresses in the CRDM housings.

To determine the extent of condition, the licensee performed ultrasonic (UT) examinations of weld No. 5 on eight additional CRDM housings. The licensee selected these housings based on being in a similar location on the head as CRDM-24, and previous cracking having been identified in some of these housings prior to the replacement of the CRDM upper housings and seal housings in 2002. The inspectors concluded that this was an adequate sample for an initial extent of condition review based upon the concept that, in light of eight negative exams, the statistical probability of a flaw in the remaining CRDM housings was very low. Additionally, the licensee planned to conduct examinations of more housings during the next refueling outage.

The inspectors concluded that the licensee actions following the 2001 leak were not adequate because the appropriate actions to preclude recurrence were within the licensee's ability to foresee and implement. Specifically, the inspectors concluded that the licensee did not effectively implement corrective actions for the 2001 CRDM housing leak resulting in the 2012 CRDM-24 housing leak.

Licensee corrective actions taken in response to the 2001 event were limited to butt welds. The inspectors reviewed the licensee actions to determine if they had been sufficient to eliminate one of the three necessary factors to cause TGSCC on the CRDM housings: (1) a susceptible material, (2) a corrosive environment and (3) tensile stress. The inspectors identified that the licensee had failed to eliminate one or more of the necessary factors at weld No. 5 (which was not a butt weld) to preclude TGSCC in the replacement housing. Specifically:

- The licensee's 2001 RCR documented that weld No. 5 is exposed to essentially the same environment as the weld that experienced the cracking (corrosive environment remained unchanged).

- No analysis was completed on the stress conditions for weld No. 5 prior to approving the modified replacement housing design (the potential for residual tensile weld stresses on ID of CRDM surface was not ruled out by analysis and therefore, should have been considered).

- Fabrication restrictions to prohibit grinding were not applied to weld No. 5 (grinding promotes residual tensile stress state on ID of CRDM surface).

- Machining was performed on weld No. 5 during the fabrication process in order to achieve the dimensions and geometry specified in the design. This process induced cold work stresses in the weld.

- Material was changed from type 347 to type 316 stainless steel (both materials are essentially equally susceptible to TGSCC).

Also, in 1991, the Fort Calhoun plant had experienced through-wall leakage due to TGSCC at weld No. 5 of its CRDM housings (same housing design) and this operational experience had been reviewed by the licensee and dismissed. In the licensee's 2001 root cause evaluation, the licensee reviewed the weld build-up region failure by TGSCC at Fort Calhoun and concluded it would not occur at Palisades. This conclusion was based on the assumption that a higher oxygen environment (more aggressive environment) would exist in the Fort Calhoun housings than in the inservice Palisades housings. However the licensee did not confirm this assumption, nor did the licensee perform additional testing to determine if the environment of their inservice housings was sufficiently benign to prevent TGSCC. The licensee's 2012 RCT reached a similar conclusion and documented that due to organizational/ programmatic weakness at Palisades, the 1991 Fort Calhoun operating experience was not adequately utilized to include inspection of the weld No. 5. The inspectors identified that the licensee had missed a key opportunity to implement effective corrective actions that could have prevented recurrence of the 2001 leakage event and elected not to pursue. Specifically, in EA-EAR-2001-0426-01 the licensee considered fabricating the replacement housings with Inconel 600 material because it was much more resistant to TGSCC, but ultimately decided not to do so. Additionally, various vendor reports were generated related to this issue in the mid 2000's. Those reports documented the potential susceptibility of weld No. 5 to TGSCC based upon a review of the CRDM housing conditions and available operating experience. The reports also noted that weld No. 5 was not inspected in any of the housings in 2001. One report in 2003 noted that weld No. 5 should have been examined as part of the action from the 2001 events since it was similar to Fort Calhoun. The issuance of these documents represented another opportunity for the licensee to identify the susceptibility of weld No. 5 to TGSCC prior to the cracking in CRDM-24.

The inspectors concluded the corrective actions taken in response to the 2001 CRDM through wall leak from TGSCC, a SCAQ, were not effective to preclude repetition. In particular, a through wall leak did recur on a CRDM from TGSCC. This issue was within the licensee's ability to foresee and correct; therefore, the issue was a performance deficiency. During the 2012 NRC special inspection, the NRC identified an URI for the TS pressure boundary leak. LCO 3.4.13 does not allow any pressure boundary leakage.

Further, Action B, associated with this LCO, requires shutdown to mode 3 in 6 hours and mode 5 in 36 hours for such leakage. The licensee determined the CRDM-24 leakage commenced on or around July 14, 2012, and the plant continued to operate in this condition until August 12 2012. Because the licensee was not aware of the existence of pressure boundary leakage, it failed to shut down the unit in six hours for a pressure boundary leak as required by TS 3.14.13 Action B. The NRC previously assessed the site's action for increasing unidentified leakage as part of the SIT. The NRC determined, at the time of higher unidentified leakage, the site took appropriate actions to attempt to locate the leak, eventually shutting down around .3 gallons per minute (gpm) leakage (earlier than the TS value of 1 gpm value for unidentified leakage). The licensee did not identify the source of the leakage as pressure boundary leakage until the shutdown on August 12, 2012, when a tour near the vessel head revealed the leaking housing. The pressure boundary leakage resulted in a TS violation due to the performance deficiency associated with the above mentioned Criterion XVI violation

Based on the review discussed above, URIs 05000255/2012012-01 "TS for PCS Pressure Boundary Leakage" and 05000255/2012012-03 "Potential Failure to Take Corrective Actions to Prevent Recurrence of a Significant Condition Adverse to Quality" are closed.

Analysis: The inspectors determined that the licensee's failure to prevent recurrence of TGSCC of the CRDM housings (a SCAQ) that resulted in a violation of TS was a performance deficiency that warranted a significance evaluation. The inspectors determined that this issue was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because it adversely affected the Initiating Events Cornerstone objective to limit the likelihood of events that upset plant stability. The issue was associated with the attribute of equipment performance. Specifically, the licensee did not take adequate corrective actions to prevent recurrence of leakage in CRDM housings which represents pressure boundary leakage. In accordance with Table 2 "Cornerstones Affected by Degraded Condition or Programmatic Weakness" of IMC 609, Attachment 4 "Initial Characterization of Findings" issued June 19, 2012, the inspectors checked the box under the Initiating Events Cornerstone because the failure of a CRDM housing is a Primary System LOCA initiator contributor.

The inspectors determined this finding was of very low safety significance (Green) based on answering "no" to the Exhibit 1 "Initiating Events Screening Questions," in IMC 0609 Attachment A "The Significance Determination Process (SDP) for Findings At-Power" issued on June 19, 2012. Specifically, the inspectors answered "no" to the screening question associated with exceeding the reactor coolant system leak rate for a small LOCA and "no" to the question associated with whether the finding could have likely affected other systems used to mitigate a LOCA resulting in a total loss of their function. The inspectors answered no to these questions because of the slow rate of change for leakage for this cracking mechanism and this type of material. Type 316 stainless steel material under TGSCC will experience leakage rates well below a small break LOCA which would be observed through the crack, alerting operators to take action to shut down the plant prior to experiencing a component rupture.

The cause of this finding, non-conservative decision making, occurred over ten years ago and is well outside of the nominal 3 year period in IMC 0612; and would not be indicative of current performance, unless there were other opportunities to identify the

issue; therefore, the inspectors concluded this was not indicative of current performance. However more recently, the licensee exhibited non-conservative decision making with respect to addressing the potential for CRDM housing cracking and leakage during the recent root cause (Section 4OA2.3 (b.2) of this report), resulting in another finding. This cross-cutting aspect will be captured through the other finding.

Enforcement: During this inspection, the inspectors identified two NCVs of NRC requirements:

Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that, for significant conditions adverse to quality, the cause of the condition is determined and corrective action taken to preclude repetition.

TS LCO 3.4.13 requires PCS operational leakage be limited to "No pressure boundary LEAKAGE" when in Modes 1 through 4.

Contrary to the above, as of August 12, 2012, the licensee had failed to take corrective actions to preclude repetition for a SCAQ. Specifically, on June 21, 2001, the licensee discovered a through wall leak in CRDM-21 due to TGSCC and failed to reasonably include weld No. 5 in the corrective actions which resulted in a subsequent through wall leak in CRDM-24 due to TGSCC.

Contrary to the above, on or around July 14, 2012, PCS pressure boundary leakage at CRDM-24 existed while in Mode 1. Further, because the licensee was not aware that the leakage was PCS pressure boundary leakage, the licensee did not implement the associated TS action statement.

As a result of the second through wall leak, the licensee took corrective actions which included the development of an inspection plan that would inspect weld No. 5 every outage until all CRDM housings were inspected.

Because these violations were of very low safety significance and were entered into the licensee's corrective action program as CR-PLP-2013-01134, these violations are being treated as an NCVs, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000255/2013002-xx; Failure to Take Coorective Action to Prevent Recurrence of CRDM Pressure Boundary Leakage).

.2 Failure to Adequately Address the Generic Implications of the Cracking identified in CRDM-24

Introduction: The inspectors identified a Finding with an associated NCV of 10 CFR Part 50, Appendix B, Criterion V, for the licensee's failure to accomplish quality activities in accordance with the prescribed procedures. Specifically, the licensee failed to adequately evaluate and document the generic implications of the cause of the cracking identified in CRDM-24 in accordance with root cause procedure EN-LI-118. This issue was entered into the licensee's corrective action program under CR-PLP-2013-05623.

Description: As a result of the cracking identified in CRDM-24, which was characterized as a SCAQ, the licensee performed a root cause evaluation in accordance with procedure EN-LI-118, "Root Cause Evaluation". This procedure was identified as quality related and served to implement control pursuant to the licensee's quality assurance

program. While reviewing the 2012 RCR (CR-PLP-2013-05623) related to the cracking identified in CRDM-24, the inspectors identified that the licensee had not appropriately considered the generic implications of the cracking in the extent of condition review. The licensee's proposed corrective actions, as a result of the 2012 RCR, narrowly focused on weld No. 5, instead of also including broader actions to ensure other CRDM housing welds were fit for their intended service life. These corrective actions consist of performing inspections of welds No. 5 on all CRDM housing.

On March 13, 2013, the inspectors requested that the licensee provide the bases for excluding other CRDM housing welds (weld No. 3 below weld No. 5 and weld No. 4 above weld No. 5) from the 2012 RCR scope of planned corrective actions. On March 29, 2013, the licensee provided additional information to justify excluding these welds from the scope of the corrective actions. The licensee credited the corrective actions associated with the modifications to the CRDM housing design completed in 2001 as the basis to exclude housing welds No. 3 and No. 4 from additional actions to identify the extent of TGSCC. The corrective actions taken in 2001 included performing heat sink welding, which is a methodology used to reduce the stresses on the inner ID of the weld. The licensee also changed the design to reduce design stresses at weld No. 3 and specified a smoother surface finish (RMS 125) to reduce potential crack initiation points. The licensee stated that these actions would produce compressive stresses on the ID of welds No. 3 and No. 4 making them immune from cracking. The inspectors acknowledged that these actions would reduce the tensile stress at the ID surface and thus reduce the probability of initiating TGSCC. However, the information provided did not demonstrate that TGSCC would not occur because it did not demonstrate that tensile stress would be eliminated at the ID surface during operation.

The inspectors identified that the three factors required for TGSCC could still be present at welds No. 3 and No. 4 as follows:

- Corrosive environment – Weld No. 3 would operate in a similar environment as weld No. 5 of the CRDM housing. Weld No. 4 would be exposed to a lower operating temperature than weld No. 5, however, TGSCC can still occur at 250 degrees Fahrenheit as evidenced by the Palisades previous operating experience with cracking identified in the seal housings that operate at even lower temperatures.

- Susceptible material – Welds No. 3 and No. 4 are composed of the same weld filler and base metal materials as weld No. 5 (e.g. weld filler material consistent with the type 316 stainless housing base metal). This material would be equally susceptible to TGSCC, as the type 347 stainless steel and weld filler materials used in the pre-2001 CRDM housing design that developed a through wall leak caused by TGSCC at weld No.3.

- Tensile stresses - While it is assumed that the corrective actions taken in response to the 2001 leak will reduce the potential for tensile stresses to exist on the inner surface of CRDM housings at welds No. 3 and No. 4, especially in light of the repairs made to welds No. 3 and No. 4, it had not been conclusively demonstrated that these tensile stresses have been eliminated. As such, when evaluating welds No. 3 and No. 4 for applicability to the 2012 root cause, it was not reasonable to conclude that tensile stresses were not present, and therefore, the potential for TGSCC had been eliminated.

The 2012 RCR discussed manufacturing irregularities and misalignment between CRDM-24 and the support tube, seismic supports, and the associated reactor head penetration/CRDM nozzle as potential source of stresses leading to cracking. However, the RCR also stated that "based on the lack of cracking found in the other eight upper housings tested, the failed CRDM-24 upper housing contains an as-yet unidentified additional stress." Because the cause of the additional stress was not identified, the licensee had not established a basis in the RCR to exclude welds No. 3 and No. 4 from the extent of condition review (e.g. potential generic implications). In 2001, assumptions on crack growth rate and inspection intervals for welds No. 3 and No. 4 were made based on the information known at the time. The 2001 crack went through-wall after the CRDM was in service for 30 years and the cracking was widespread among the other CRDM housings. In 2012, the crack propagated through-wall after the CRDM was in service for 11 years and the cracking did not appear as widespread. Though TGSCC was a factor in both cracking events, there are still unknowns associated with the 2012 incident. The unknown additional stresses, as well as the time the CRDM was inservice before cracking in 2012, represent key differences as related to the cracking identified in 2001. In the 2012 RCR, the licensee did not consider these or other potential differences between the two incidents when determining not to include welds No. 3 and No. 4 in the evaluation and documentation of the generic implications of the root and contributing causes and therefore, did not provide a justification for excluding welds No. 3 and No.4 from this evaluation or corrective actions.

The inspectors identified that the licensee had not followed Procedure EN-LI-118 "Root Cause Evaluation," in the root cause review of the CRDM-24 leak as documented in report CR-PLP-2013-05623. Section 5.5 (12)e of EN-LI-118 required that the licensee "perform an extent of cause evaluation by reviewing the individual Root and Contributing causes for generic implications to establish whether the causes can affect other SSC's." Additional details are provided in the procedure on how to conduct and document the evaluation. In this case, the inspectors identified that the licensee had not addressed or documented a basis in RCR CR-PLP-2013-05623 to exclude welds No. 3 and No. 4 from the generic factors discussed above that led to the 2012 leak in CRDM-24 (e.g. TGSCC at weld No. 5) to meet the procedural requirement. The licensee entered this issue into the corrective action program as CR-PLP-2013-01500. To restore compliance with the procedure, the licensee intended to revise the inspection plan to add additional corrective actions to inspect a sample of welds No. 3 and No. 4 for TGSCC during the upcoming refueling outage.

Analysis: The inspectors determined that the failure to adequately evaluate and document the generic implications of the cause of the cracking identified in CRDM-24 in accordance with the root cause procedure EN-LI-118 was a performance deficiency that warranted a significance evaluation. The inspectors determined that this issue was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because it adversely affected the Initiating Events Cornerstone attribute of equipment performance. The inspectors also answered "yes" to the More-than-Minor screening question "if left uncorrected, would the performance deficiency have the potential to lead to a more significant safety concern?" Specifically, absent NRC identification, the licensee would not have completed further evaluations or inspections of CRDM housing welds which could have resulted in additional CRDM housing failure and leakage by TGSCC. In accordance with Table 2 "Cornerstones Affected by Degraded Condition or Programmatic Weakness" of IMC 609, Attachment 4 "Initial Characterization of Findings" issued June 19, 2012, the inspectors checked the

box under the Initiating Events Cornerstone because the failure of a CRDM housing is a Primary System LOCA initiator contributor.

The inspectors determined this finding was of very low safety significance (Green) based on answering "no" to the Exhibit 1 "Initiating Events Screening Questions," in IMC 0609, Attachment A "The Significance Determination Process (SDP) for Findings At-Power" issued on June 19, 2012. Specifically, the inspectors answered "no" to the screening question associated with exceeding the reactor coolant system leak rate for a small LOCA and "no" to the question associated with whether the finding could have likely affected other systems used to mitigate a LOCA resulting in a total loss of their function. The inspectors answered no to these questions because of the inherent toughness (e.g. flaw tolerance) of the type 316 stainless steel material such that leakage rates well below a small break LOCA would be observed through inservice cracks and actions taken to correct them prior to experiencing a large component rupture.

The inspectors determined that the primary cause of the failure to adequately consider welds No. 3 and No. 4 in the generic implications section of the RCR related to the cross-cutting component of Human Performance, Decision Making, because licensee staff did not use conservative assumptions in decision making. Specifically, the licensee did not use conservative assumptions when excluding welds No. 3 and No. 4 as being susceptible to TGSCC and therefore include them in the generic implications section of the RCR. (Item H.1(b) of IMC 310).

Enforcement: During the inspection, the inspectors identified one NCV of NRC requirements:

Title 10 CFR Part 50, Appendix B, Criterion V "Instructions, Procedures and Drawings requires in part, activities affecting quality shall be prescribed by documented procedures and shall be accomplished in accordance with these procedures.

Procedure EN-LI-118 "Root Cause Evaluation Process," Revision 17 states:

- 5.5 (12)e: perform an extent of cause evaluation by reviewing the individual Root and Contributing causes for generic implications to establish whether the causes can affects other SSCs , organizations or work processes. Use the two step process in accordance with attachment 9.7
- Attachment 9.7: Determine whether the occurrence/consequence (problem) is isolated, or whether it has broader (generic or common mode) implications. Achieve this by asking the following questions:
    i. Could this happen to equipment that is similar in function, design, or service condition?
    ii. Could this happen to a group of components? (components of the same construction or materials that could be similarly affected by one condition)
- Attachment 9.7: Document the results of the above considerations. Include the following items in the write up:
    i. Generic Implications (Is this problem/ cause limited to this component/equipment, or does it apply to others as well)
    ii. Existing broader (generic/common mode) considerations

- 5.5(15)(10)c&f: Document proposed corrective actions and due dates to address valid generic implications. If no corrective action is recommended for a valid generic implication then document the basis for this conclusion and any risk or consequence identified as a result of taking no action.

Contrary to the above, from February 24, 2013 through April 18, 2013, the licensee failed to accomplish activities affecting quality in accordance with procedure EN-LI-118, which was being implemented to correct a SCAQ. Specifically, the licensee failed to accomplish step 5.5 (12)e by not fully evaluating and documenting the existing broader (generic/common mode) considerations, extent of condition/cause associated with TGSCC at CRDM housing welds No. 3 and No. 4, including considering the susceptibility of the welds to TGSCC and performing subsequent inspections or evaluations.

The licensee intends to revise the inspection plan to add additional corrective actions to inspect a sample of welds No. 3 and No. 4 for TGSCC during the upcoming refueling outage.

Because of the very low safety significance and because the licensee entered this issue into their corrective action program (CR-PLP-2013-01500), it is being treated as a NCV consistent with Section 2.3.2 of the Enforcement Policy (NCV 05000255/2013003-xx Failure to Adequately Address the Generic Implications of the Cracking Identified in CRDM-24).

4OA5 Other Activities

.1 (Closed) Unresolved Item 05000255/2012012-02: Potential Inadequate Degradation Evaluation of CRDM Housings (This inspection is part of the additional inspections included in the Palisades Deviation letter)

During a Special Inspection performed in August 2012, NRC inspectors identified an issue which could not be resolved without additional information (URI). This issue was associated with the rate of growth of the crack which created the through wall leak in CRDM-24, discovered on August 12, 2012. Identification of this crack growth rate is significant in determining appropriate intervals for future inspections to provide reasonable assurance that CRDM housing leakage will not recur.

Preliminary failure analysis data available at the time of the inspection indicated that the observed cracking was due to TGSCC. Cracking of this type is normally due to the presence of oxygen and chlorides at the location of the crack. When examining the fracture surface at the location the through-wall leak occurred, the licensee identified six concentric rings (beach marks) propagating in a radial direction from the ID out towards the OD of the housing. Beach marks are normally associated with fatigue failures and indicate the number of stress cycles from crack initiation to crack failure. In this case, there was no evidence that fatigue contributed to the failure. Despite the lack of evidence of fatigue, it was apparent that the crack which resulted in the CRDM-24 leak grew in increments. It was not, however, immediately apparent whether the increments were related to oxygen ingress (refueling outages) or temperature/pressure cycles (heatups/cooldowns).

At the time of the original inspection, five time intervals for through wall crack growth were under consideration. Two were based on literature crack growth data and three were based on interpretations of the beach marks. These time intervals were:

- Based on literature data, one contractor estimated that a 10% through wall flaw would require four years to reach 50% through wall.
- Based on literature data another contractor estimated the crack growth rate to be 2.1 x 10^{-5} in/hr or 0.18 in/yr. This is approximately three times faster than the crack growth rate proposed in the above mentioned rate.
- Based on the concept of oxygen ingress at refueling outages six cycles of 18 months duration would require nine years for the crack to grow through wall
- Based on the concept of temperature/pressure cycles, the plant experienced six cold shutdowns in approximately two years preceding the crack. This equates to two years for the crack to grow through wall.
- Based on the concept that oxygen is required for crack growth and that oxygen is rapidly purged from the CRDM housings due to leakage past the seals, crack growth occurs only during the first few weeks of operation following a refueling outage, followed by no growth for the remaining period of operation when oxygen concentrations are low. This equates to six oxygen ingress events (irrespective of time between events) for the crack to grow through wall.

NRC inspectors including technical experts from NRC Headquarters performed a follow-up inspection to determine if the assumptions made by the licensee were conservative and the planned actions bounded those conservative assumptions. The inspectors reviewed a variety of documents associated with crack growth and inspection intervals. The inspectors noted the following statements included in the RCR and vendor documents related to the determination of the appropriate crack growth rate:

- The laboratory conducting the failure analysis concluded, it could not be conclusively determined if the beach marks corresponded to refueling outages, (i.e., 18 month cycle) or shorter periods as occurred during outages over the past 24 months
- Palisades CRDM-21 leaked at weld No. 3 in 2001. The fracture surface of the crack leading to this leak contained beach marks identical to those in the 2012 failure. In calculating the crack growth rate of this crack, one contractor utilized an interval between beach marks which is much shorter than refueling outages. The intervals used are consistent with plant thermal cycles in which oxygen may or may not have been admitted into the CRDMs.
- A CRDM housing at Ft Calhoun leaked at weld No. 5 in 1990. The fracture surface of the crack leading to this leak contained beach marks identical to those in the 2012 Palisades failure. In calculating the crack growth rate of this crack, Ft Calhoun stated that the beach marks were related to refueling cycles. Ft Calhoun also performed calculations indicating that the oxygen level at the location of the flaw did not change with time (including in response to refueling outages) because the CRDM housing was not vented. Ft Calhoun's evaluation indicated that oxygen levels at the vicinity of the crack would have begun to decline through diffusion and convection had the intervals between outages been much longer than 18 months. This is interpreted to mean that the beach marks at Ft Calhoun are in response to pressure/thermal cycles.
- In at least one instance, Palisades needed to repair the seals on a reactor coolant pump at a time other than an outage. This necessitated draining some of the water

from the reactor coolant system and venting (admitting oxygen into) the CRDM housing. This represented an additional oxygen ingress event not included when determination of time to cracking is based on refueling outages.

- In its inspection plan, Palisades stated that it will inspect all CRDM housings over the next four refueling outages, i.e., the interval between inspections is one refueling outage

Based on the above review, the inspectors noted that there were certain non conservative statements contained in the RCR and the inspection plan. These included:

- The crack growth rate based on refueling outages was understated. If oxygen ingress is related to beach marks, given the oxygen ingress event which occurred to repair reactor coolant pump seals, six beach marks would occur in a maximum of five refueling intervals rather than the six refueling intervals that were used to calculate the crack growth rate in the RCR.
- The crack growth rate based on heat up and cool down cycles is overstated. The value in the root cause is based on 11 months. While six shutdowns did occur at the plant in 11 months several of these events did not result in pressure/temperature changes of the reactor coolant system. The appropriate time frame is 24 months rather than 11.
- The inspection plan contains a non conservative statement: "However, once the crack has been initiated it propagates over four to five operating cycles prior to going through wall." While this statement does reflect one of the proposed theories for crack growth, sufficient evidence to demonstrate reasonable assurance that this theory is correct, and thereby overcome the non-conservatism of this statement, was not provided.

Despite the existence of the non conservatisms stated above, the inspectors concluded:

- Sufficient evidence to conclusively determine the rate of crack growth does not exist.
- Crack growth based on pressure/temperature cycles is the most conservative of the potential crack growth mechanisms. In the absence of reasonable assurance of the correctness of less conservative mechanisms, through wall crack growth in two years must be utilized for regulatory purposes.
- The licensee has not formally committed to any of the crack growth mechanisms discussed.
- The licensee's inspection program includes inspection of all of the CRDM housings over the next four refueling outages. Approximately 25% of the housings will be inspected during each outage. The inspection of 25% of the CRDM housings each interval is sufficient to indicate that, in the event no indications are found during a given inspection, that the probability that flaws exist in other housings is extremely low. As such, it may be considered that the inspection of approximately 25% of the CRDM housings every refueling outage bounds all the crack growth rate mechanisms considered.

Overall, some weaknesses did exist in the site's assessment, but none of these issues arose above the level of a minor performance deficiency for the evaluations completed. With the corrective actions in place to monitor the CRDMs, the inspectors considered this approach to inspection to be both acceptable and sufficient justification to close this URI.

4OA6 Management Meetings

.2 Interim Exit Meetings

An interim exit was conducted for:

- The results of the selected issue follow-up inspection, with Mr. T. Vitali, Site Vice President on April 18, 2013.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

B. Davis, Engineering Director
O. Gustafson, Licensing Manager
T. Foudy, Engineering Supervisor
B. Williams, Engineer
B. Dotson, Licensing

LIST OF ITEMS OPENED, CLOSED, DISCUSSED

Closed

05000255/2012012-01	URI	TS for PCS Pressure Boundary Leakage
05000255/2012012-02	URI	Potential Inadequate Degradation Evaluation of CRDM Housings
05000255/2012012-03	URI	Potential Failure to Prevent Recurrence of a Significant Condition Adverse to Quality

Opened and Discussed

None.

LIST OF DOCUMENTS REVIEWED

The following is a partial list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety, but rather that selected sections or portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

4OA2 Identification and Resolution of Problems

4OA5 Other Activities

LIST OF ACRONYMS USED

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
1600 EAST LAMAR BLVD
ARLINGTON, TEXAS 76011-4511

[DATE]

EA-12-023

David J. Bannister, Vice President
and Chief Nuclear Officer
Omaha Public Power District
Fort Calhoun Station FC-2-4
P.O. Box 550
Fort Calhoun, NE 68023-0550

SUBJECT: FINAL SIGNIFICANCE DETERMINATION FOR A RED FINDING AND NOTICE OF VIOLATION, NRC INSPECTION REPORT 05000285/2011014, FORT CALHOUN STATION

Dear Mr. Bannister:

This letter provides you the final significance determination of the preliminary Red finding discussed in our previous communication dated March 12, 2012, which included the subject inspection report. The finding involved deficient modification and maintenance of the safety-related 480 Vac electrical distribution system and a failure to maintain in effect all provisions of the approved fire protection program.

In your letter dated March 22, 2012, you indicated that Omaha Public Power District did not contest the characterization of the risk significance of this finding and that you declined your opportunity to discuss this issue in a Regulatory Conference or to provide a written response.

The NRC has also determined that the failure to ensure that the 480 Vac electrical power distribution system design requirements were properly implemented and maintained through proper maintenance, modification, and design activities along with the failure to implement and maintain in effect all provisions of the fire protection program are violations of NRC requirements, as cited in the attached Notice of Violation (Notice). The circumstances surrounding the violations were described in detail in the subject inspection report. In accordance with the NRC Enforcement Policy, the Notice is considered escalated enforcement action because it is associated with a Red finding.

Outside of Scope

Withhold

D-3

WITHHOLD

Outside of Scope

(b)(5)

DRAFT- NOT IN FINAL

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 no response is required add: "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 Web site at http://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,

E. Collins

Regional Administrator

Docket: 50-285
License: DPR-40

Enclosures:
1. Notice of Violation
2. Failure to Ensure that the 480 Vac Electrical Power Distribution System Design Requirements were Implemented and Maintained – Final Significance Determination

R:\

ADAMS: ☐ No X Yes	X SUNSI Review Complete	Reviewer Initials: STG
Category B.1	X Publicly Available	X Non-Sensitive
Category A.	☐ Non-publicly Available	☐ Sensitive
KEYWORD:		

SRI:DRS/EB2	C:DRS/EB2	SRA:DRS	C:DRP/F	C:ACES
SGraves	GMiller	DLoveless	JClark	HGepford
D:DRP	D:DRS	OE	Regional Counsel	DRA
KKennedy	AVegel	G. Gulla	KFuller	AHowell
RA				
ECollins				

OFFICIAL RECORD COPY T=Telephone E=E-mail F=Fax

NOTICE OF VIOLATION

Omaha Public Power District
Fort Calhoun Station

Docket No.: 05000285
License No.: DPR-40
EA-12-023

During an NRC inspection conducted from September 12, 2011, to February 29, 2012, violations of NRC requirements were identified. In accordance with the NRC Enforcement Policy, the violations are listed below:

Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part that: (1) design changes, including field changes, be subject to design control measures commensurate with those applied to the original design; (2) measures be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions; and (3) these measures assure that appropriate quality standards are specified and included in design documents and that deviations from such standards are controlled.

Contrary to the above requirement, from November 2009 to June 7, 2011, the licensee failed to ensure that design changes were subject to design control measures commensurate with those applied to the original design; failed to assure that applicable regulatory requirements and the design basis for those safety-related structures, systems, and components were correctly translated into drawings, procedures, and instructions; and failed to ensure that these measures assured that appropriate quality standards were specified and included in the design documents. Specifically, design reviews, work planning and instructions for a modification to install new 480 Vac load center breakers failed to ensure that the cradle adapter assemblies had low resistance connections with the switchgear bus bars by establishing a proper fit and requiring low resistance connections to assure that design basis requirements were maintained.

Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures be established to assure that conditions adverse to quality such as failures, defective material and equipment, and nonconformances are promptly identified and corrected. For significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.

Contrary to the above requirement, from May 22, 2008, to June 7, 2011, the licensee failed to correct a significant condition adverse to quality and take corrective actions to preclude repetition. Specifically, the licensee failed to ensure that their preventative maintenance program for the safety-related 480 Vac electrical power distribution system was adequate to ensure proper cleaning of conductors, proper torquing of bolted conductor or bus bar connections, and adequate inspection for abnormal connection temperatures. In 2008, the licensee identified that preventative maintenance procedure EM-PM-EX-1200, "Inspection and Maintenance of Model AKD-5 Low Voltage Switchgear," was less than adequate as a result of a root cause analysis for the failure of bus-tie breaker BT-1B3A to close on demand and loss of bus 1B3A. The licensee categorized this failure as a significant condition adverse to quality. The analysis concluded that breaker BT-1B3A had high resistance connections which occurred as a result of both procedure deficiencies and inadequate implementation resulting in the failure to remove dirt and hardened grease from electrical connections. The licensee

implemented corrective actions to address these procedural deficiencies; however the corrective actions were inadequate to prevent high resistance connections in load center 1B4A due to the presence of hardened grease and oxidation. The procedure did not contain adequate guidance for torquing bolted connections or measuring abnormal connection temperatures due to loose electrical connections in the bus compartment of the switchgear.

License Condition 3.D, "Fire Protection Program," requires, in part, that the licensee implement and maintain in effect all provisions of the approved Fire Protection Program as described in the Updated Safety Analysis Report and as approved in NRC safety evaluation reports. Section 9.11.1 of the Updated Safety Analysis Report describes the fire protection system design basis and states, in part, that the design basis of the fire protection systems includes commitments to 10 CFR Part 50, Appendix R, Section III.G. Section III.G, "Fire protection of safe shutdown capability," requires, in part, that fire protection features be provided for structures, systems, and components important to safe shutdown, and that these features be capable of limiting fire damage so that one train of systems necessary to achieve and maintain hot shutdown conditions is free of fire damage.

Contrary to the above requirement, from November, 2009, to June 7, 2011, the licensee failed to implement and maintain in effect all provisions of the approved Fire Protection Program. Specifically, the licensee failed to ensure that design reviews for electrical protection and train separation of the 480 Vac electrical power distribution system were adequate to ensure that a fire in load center 1B4A would not adversely affect operation of redundant safe shutdown equipment in load center 1B3A, such that one train of systems necessary to achieve and maintain hot shutdown conditions were free of fire damage. Combustion products from the fire in load center 1B4A migrated across normally open bus-tie breaker BT-1B4A into the non-segregated bus duct, shorting all three electrical phases. The non-segregated bus ducting electrically connected load center 1B4A with the Island Bus 1B3A-4A and, through normally closed bus-tie breaker BT-1B3A, to the redundant safe shutdown train.

These violations are associated with a Red SDP finding.

Pursuant to the provisions of 10 CFR 2.201 Omaha Public Power District is hereby required to submit a written statement or explanation 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). This reply should be clearly marked as a "Reply to a Notice of Violation; EA-12-023" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

If you contest this enforcement action, you should also provide a copy of your response, with

the basis for your denial, to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

Because 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 Web site at http://www.nrc.gov/reading-rm/adams.html, to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

In accordance with 10 CFR 19.11, you may be required to post this Notice within two working days of receipt.

Dated this__ day of March 2012.

SERP Worksheet for SDP-Related Findings

SERP Date:

Cornerstone Affected and Proposed Preliminary Results: Initiating Events - Red Violation

Licensee: Omaha Public Power District
Facility/Location: Fort Calhoun Station
Docket No(s): 50-285
License No: DPR-40
Inspection Report No: 05000285/2011014
Date of Exit Meeting: TBD
Issue Sponsor: Region IV/Division of Reactor Safety

Meeting Members
Issue Sponsor: Tony Vegel, Director, DRS, RIV
Technical Spokesperson(s): Sam Graves, Senior Reactor Inspector
Program Spokesperson: TBD
OE Representative: TBD

A. Brief Description of Issue

Inadequate maintenance and inadequate modification contributed to a catastrophic switchgear fire that started in a 480-volt feeder breaker by creating one or more high-resistance connections within the switchgear. Smoke and soot from the fire migrated to a bus cross-tie, causing an additional electrical fault that affected the opposite train. The electrical separation scheme failed to function as designed in two locations. Between the actual electrical system response and the operator response per procedures, six of the nine 480-volt load center buses were de-energized. While the event occurred with the plant in cold shutdown for a planned refueling outage, the breakers could have failed at any time from their installation until the failure occurred, a time frame of approximately 19 months.

Also, the NRC had previously (2009) concluded that the licensee was performing inadequate maintenance on their safety-related breakers and switchgear. Since the violation was issued in early 2010, the licensee has not changed their maintenance practices to address the deficiencies which contributed to this event. This inspection identified concerns with failure to clean hardened grease from bus work and connections, work instructions that allowed workers to ignore most of the bus work because it could be considered difficult to access, failure to torque bolted bus connections and/or failure to document torquing them, plus not specifying the required torque values. Each of these concerns, along with photographs of the damage and results of reports from forensics experts, led the NRC to conclude that the lack of maintenance had an equal likelihood of contributing to the fire as the modification problems. Due the catastrophic nature of the damage, the exact cause cannot be determined.

The event showed unexpected electrical system interactions. The fault resulted in the unexpected tripping of the opposite train feeder breaker instead of the intermediate bus-tie breaker as was expected by design. This de-energized both the redundant train bus and the island bus. Also, the fire in 1B4A caused grounded circuits on both trains of Class 1E 125-volt

dc distribution. The apparent lack of separation for the 480-volt system is still being evaluated by the licensee.

The inspection noted that, during the 3 days prior to the fire, the licensee failed to adequately investigate the source of an acrid odor that was reported in the switchgear room, and therefore failed to prevent the resulting catastrophic electrical fault and fire.

B. Statement of the Performance Deficiency

Failure to ensure that the design requirements for the 480-volt electrical power distribution system were maintained through proper maintenance, modification, and design reviews was a performance deficiency. Specifically: (1) preventive maintenance activities were inadequate to ensure proper cleaning of conductors, proper torquing of bolted conductor or bus bar connections, or adequate inspection for abnormal connection temperatures; (2) design reviews and work planning for a modification to install new 480-volt load center breakers failed to ensure that the cradle adapter assemblies had a low-resistance connection with the bus bars by establish a proper fit and requiring low resistance measurements; and (b)(5) [redacted]
(b)(5) [redacted]

DRAFT
DRAFT
FROM
FINAL

C. Significance Determination Basis

1. Reactor Inspection for IE, MS, B cornerstones

a. Phase 1 screening logic, results and assumptions
In accordance with NRC Inspection Manual Chapter 0612, Appendix B, "Issue Screening," this finding was determined to be more than minor because it was associated with both the protection against external events attribute (i.e., fire) and the design control attribute of the Initiating Events cornerstone. The finding affected the Initiating Events cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the performance deficiency elements each contributed to making it more likely that Fort Calhoun Station could have a significant fire in the safety-related bus work that would upset plant stability and challenge critical safety functions. Mitigating systems were actually affected during the event and Barrier Integrity (spent fuel pool cooling could be impacted), but it was determined that the Initiating Events cornerstone was the most appropriate cornerstone for this finding because it best reflects the dominant risk associated with the finding.

The finding was best characterized as a transient initiator in Table 4a, and was determined to contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. Therefore, the Table 4a directs the user to Appendix A for further analysis.

b. Phase 2 Risk Evaluation (when applicable)
(b)(5) [redacted]

NOT IN FINAL

ex 5

DRAFT NOT IN FINAL

(b)(5)

Outside of Scope

D. Proposed Enforcement.

a. Regulatory requirement not met.
10 CFR Part 50, Appendix B, Criterion III, "Design Control."

10 CFR 50, Appendix B, Criterion XVI, "Corrective Action"

b. Proposed citation.
10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part that 1) design changes, including field changes, be subject to design control measures commensurate with those applied to the original design; 2) measures be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions; and 3) these

measures assure that appropriate quality standards are specified and included in design documents and that deviations from such standards are controlled.

Contrary to these requirements, from November 2009 to June 7, 2011, the licensee failed to ensure that design changes were subject to design control measures commensurate with those applied to the original design, and failed to assure that applicable regulatory requirements and the design basis, as defined in § 50.2 and as specified in the license application, for those safety-related structures, systems, and components were correctly translated into specifications, drawings, procedures, and instructions.

10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part that...

Outside of Scope

SERP Worksheet for SDP-Related Findings

SERP Date:

Cornerstone Affected and Proposed Preliminary Results:

Licensee:
Facility/Location:
Docket No(s):
License No:
Inspection Report No:
Date of Exit Meeting:
Issue Sponsor:

Meeting Members
Issue Sponsor:
Technical Spokesperson(s):
Program Spokesperson: Geoff Miller, Chief, EB2
OE Representative:

A. Brief Description of Issue

B. Statement of the Performance Deficiency

The failure to ensure that the 480 Vac electrical power distribution system design requirements were properly implemented and maintained through proper maintenance, modification, and design activities contributed to create the conditions that allowed a catastrophic fire in a switchgear impacting the required safe shutdown capability of the plant. This was a performance deficiency. Specifically: (1) design reviews and work planning for a modification to install twelve new 480 Vac load center breakers failed to ensure that the cradle adapter assemblies had a low-resistance connection with the switchgear bus bars by establishing a proper fit and requiring low resistance measurements; (2) preventive maintenance activities were inadequate to ensure proper cleaning of conductors, proper torquing of bolted conductor and bus bar connections, or adequate inspection for abnormal connection temperatures; and (3) design reviews of the electrical protection and train separation of the 480 Vac electrical power distribution system were inadequate to ensure that a fire in load center 1B4A would not prevent operation of redundant safe shutdown equipment in load center 1B3A, as required by the fire protection program.

Outside of Scope

Outside of Scope

D. Proposed Enforcement.

a. Regulatory requirement not met.

b. Proposed citation.

Three violations were associated with this performance deficiency:

- A violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure to ensure that design changes were subject to design control measures commensurate with those applied to the original design; the failure to assure that applicable regulatory requirements and the design basis, as defined in § 50.2 and as specified in the license application, for those safety-related structures, systems, and components were correctly translated into specifications, drawings, procedures, and instructions;

- A violation of 10 CFR Part 50, Appendix B, Criterion XVI "Corrective Action," for the failure to assure that a significant condition adverse to quality was promptly identified, corrected, and measures taken to preclude repetition;

- A violation of License Condition 3.D, "Fire Protection Program," for the failure to ensure that the electrical protection and physical design of the 480 Vac electrical

power distribution system provided the electrical bus separation required by the fire protection program.

Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part that: (1) design changes, including field changes, be subject to design control measures commensurate with those applied to the original design; (2) measures be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions; and (3) these measures assure that appropriate quality standards are specified and included in design documents and that deviations from such standards are controlled.

Contrary to above requirement, from November 2009, to June 7, 2011, the licensee failed to ensure that design changes were subject to design control measures commensurate with those applied to the original design; failed to assure that applicable regulatory requirements and the design basis for those safety-related structures, systems, and components were correctly translated into drawings, procedures, and instructions; and failed to ensure that these measures assured that appropriate quality standards were specified and included in the design documents. Specifically, design reviews, work planning and instructions for a modification to install new 480 Vac load center breakers failed to ensure that the cradle adapter assemblies had low resistance connections with the switchgear bus bars by establishing a proper fit and requiring low resistance measurements to assure that design basis requirements were maintained.

Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part that measures be established to assure that conditions adverse to quality such as failures, defective material and equipment, and nonconformances are promptly identified and corrected. For significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.

Contrary to the above requirement, from May 22, 2008 to June 7, 2011, the licensee failed to correct a significant condition adverse to quality and take corrective actions to preclude repetition. Specifically, the licensee failed to ensure that their preventative maintenance program for the safety-related 480 Vac electrical power distribution system was adequate to ensure proper cleaning of conductors, proper torquing of bolted conductor or bus bar connections, and adequate inspection for abnormal connection temperatures after previous similar failures in the 480 Vac electrical power distribution system.

License Condition 3.D, "Fire Protection Program," requires, in part that Omaha Public Power District implement and maintain in effect all provisions of the approved Fire Protection Program as described in the Updated Safety Analysis Report and as approved in NRC safety evaluation reports.

Contrary to the above requirement, from November, 2009 to June 7, 2011, the licensee failed to implement and maintain in effect all provisions of the approved Fire Protection Program. Specifically, the licensee failed to ensure that design reviews for electrical protection and train separation of the 480 Vac electrical power distribution system were adequate to ensure that a fire in load center 1B4A would not

prevent operation of redundant safe shutdown equipment in load center 1B3A, as required by the fire protection program.

Outside of Scope

From: Miller, Geoffrey
To: Vegel, Anton
Cc: Blount, Tom
Subject: FW: FCS Potential Red: Regional Panel Notes
Date: Tuesday, January 31, 2012 1:26:00 PM

Tony,

There was a healthy discussion (2.5 hrs) at the regional panel for the Fort Calhoun potential Red finding this morning. Below are some of the additional actions EB2 is pursuing to prepare for the Agency SERP - the most significant in my opinion being inspection follow up on the seismic qualification of the breakers based on new information from the vendor that the licensee provided us last week (specifically, FCS provided us a letter from the vendor last week that said the breakers would have been seismically qualified in the as-found condition. There was no evaluation or analysis accompanying the letter. Sam is contacting FCS to get a copy of any analysis/evaluation the vendor used to base their conclusion so we can make a call to accept or reject the claim.) The panel recommended we pursue a 2/16 SERP date to ensure we can tie up loose ends and brief Elmo. We will have a revised package ready to route in the next week.

Please let me know if you have questions or would like additional information,

Geoff

From: Miller, Geoffrey
Sent: Tuesday, January 31, 2012 12:59 PM
To: Graves, Samuel; Loveless, David
Subject: FCS Potential Red: Regional Panel Notes

Sam/Dave,

Great job at the panel this morning – there was a lot of ground to cover and information to put out, and I thought we were able to touch on it all. Below are the takeaways I wrote down during the discussion. Please let me know if I missed anything. I would like to have a 'final' draft package ready to circulate in time to meet a 2/16 SERP (COB Monday would work great).

Thank you!

Geoff

Outside of Scope

- Obtain and inspect seismic qualification evaluation from licensee/vendor. (EB2)

- Provide risk number comparison table (sensitivity analysis) to demonstrate impact of: (1) 24 hrs vs 56 hrs, (2) seismic qualification; (3) TDAFP credit (if not already included in #1). (SRA)

- Provide risk estimate (order of magnitude) for impact of finding on shutdown risk. (SRA)

Outside of Scope

out of scope

Outside of Scope

D4

Releasable Entirely

~~OFFICIAL USE ONLY - PREDECISIONAL ENFORCEMENT INFORMATION~~

SERP Worksheet for SDP-Related Findings

EA-2012-023

SERP Date: February 23, 2012

Cornerstone Affected and Proposed Preliminary Results: Initiating Events – Preliminary Red

Licensee: Omaha Public Power District
Facility/Location: Fort Calhoun Station (FCS)
Docket No(s): 50-285
License No: DPR-40
Inspection Report No: 05000285/2011014
Date of Exit Meeting: TBD
Issue Sponsor: Region IV/Division of Reactor Safety

Meeting Members

Issue Sponsor:	Tony Vegel, Director, RIV /DRS
Technical Spokesperson(s):	Sam Graves, SRI, RIV/DRS/EB2 Geoff Miller, BC, RIV/DRS/EB2
Program Spokesperson:	TBD
RIV Enforcement Specialist:	Ray Kellar (C Maier backup RIV ES)
OE Representative:	Gerry Gulla, SES, OE/EB

A. Brief Description of Issue

Inadequate maintenance and inadequate modification contributed to a catastrophic switchgear fire that started in a safety-related 480 Vac feeder breaker. The fire was created by one or more high-resistance connections within the switchgear. The high-resistance connections occurred as a result of improper installation of new circuit breakers and inadequate switchgear maintenance. Smoke and soot from the fire migrated to a bus cross-tie, causing an additional electrical fault that adversely affected the redundant train. The electrical separation scheme failed to function as designed, and between the actual electrical system response and the operator response per procedures, six of the nine 480 Vac safety-related load center buses were de-energized. When the event occurred the plant was in cold shutdown for a planned refueling outage, however, the breakers could have failed at any time from their installation until the failure occurred, a time frame of approximately 19 months.

In 2008 the licensee identified a significant condition adverse to quality involving, in part, inadequate cleaning of hardened grease from electrical contacts and inadequate maintenance practices for 480 Vac bus-tie breakers. In 2009 the NRC concluded that the licensee was performing inadequate maintenance on their safety-related breakers and switchgear and subsequently issued a non-cited violation. The licensee had not changed their maintenance practices to address the deficiencies since the violation was issued in early 2010. This inspection identified concerns with failure to clean hardened grease from bus work and connections, work instructions that allowed workers to skip most of the bus work because it could be considered difficult to access, failure to torque bus connections and/or failure to document torquing them, and not specifying the appropriate torque values. Each of these concerns, along with images of the damage, results of reports from forensics experts and vendors, and the history of inadequate maintenance led the NRC to conclude that the lack of adequate maintenance had an equal likelihood of contributing to the fire as

the modification problems. Due to the catastrophic nature of the damage, the exact cause cannot be determined.

The event showed unexpected electrical system interactions. Combustion products from the fire in load center 1B4A migrated across normally open bus-tie breaker BT-1B4A into the non-segregated bus duct, shorting all three electrical phases. The non-segregated bus ducting electrically connected load center 1B4A with the Island Bus 1B3A-4A and, through normally closed bus-tie breaker BT-1B3A, to the redundant safe shutdown train. This resulted in de-energizing both the redundant train Bus 1B3A and the Island Bus 1B3A-4A. The fire in load center 1B4A exposed vulnerabilities in FCS implementation of electrical separation. Also, the fire in 1B4A caused grounded circuits on both trains of the Class 1E 125 Vdc distribution system. The apparent lack of separation for the 480 Vac system is still being evaluated by the licensee.

The inspection also noted that during the 3 days prior to the fire, the licensee failed to adequately investigate the source of an acrid odor that was reported in the switchgear room, and therefore failed to prevent the resulting catastrophic electrical fault and fire.

B. Statement of the Performance Deficiency

The failure to ensure that the 480 Vac electrical power distribution system design requirements were properly implemented and maintained through proper maintenance, modification, and design activities contributed to the conditions that allowed a catastrophic fire in a switchgear, which impacted the required safe shutdown capability of the plant. This was a performance deficiency. Specifically: (1) design reviews and work planning for a modification, to install twelve new 480 Vac load center breakers, failed to ensure that the cradle adapter assemblies had a low-resistance connection with the switchgear bus bars by establishing a proper fit and requiring low resistance measurements; (2) preventive maintenance activities were inadequate to ensure proper cleaning of conductors, proper torquing of bolted conductor and bus bar connections, or adequate inspection for abnormal connection temperatures; and (3) design reviews of the electrical protection and train separation of the 480 Vac electrical power distribution system were inadequate to ensure that a fire in load center 1B4A would not adversely impact operation of redundant safe shutdown equipment in load center 1B3A, as required by the fire protection program.

C. Significance Determination Basis

1. Reactor Inspection for IE, MS, BI cornerstones

a. Phase 1 screening logic, results and assumptions

In accordance with NRC Inspection Manual Chapter (IMC) 0612, Appendix B, "Issue Screening," this finding was determined to be more than minor because it was associated with both the protection against external events attribute (i.e., fire) and the design control attribute of the Initiating Events cornerstone. The finding affected the Initiating Events cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the performance deficiency elements each contributed to making it more likely that Fort Calhoun Station could have a significant fire in the safety-related bus work that would upset plant stability and challenge critical safety functions. Mitigating

systems were actually affected during the event and Barrier Integrity (spent fuel pool cooling) was impacted, but the inspectors determined that the Initiating Events cornerstone was the most appropriate cornerstone for this finding because it best reflects the dominant risk associated with the finding.

The finding was best characterized as a transient initiator in Table 4a, and was determined to contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. Therefore, Table 4a directs the user to Appendix A for further analysis.

b. Phase 2 Risk Evaluation

Appendix A to IMC 0609 directs that a Phase 3 analysis be performed if the Phase 2 SDP pre-solved tables/worksheets do not clearly address the inspection finding. A phase 3 analysis was performed for this finding because the finding involved external event initiators (fire), and the pre-solved tables do not clearly address the finding.

c. Phase 3 Analysis

The senior reactor analyst completed a Phase 3 analysis using the plant-specific Standardized Plant Analysis Risk Model for Fort Calhoun, Revision 8.15, the licensee's Individual Plant Examination of External Events, and hand calculations. The exposure period of 1 year represented the maximum exposure time allowable in the significance determination process. The analyst estimated the initiating event likelihood for a single fire of 7.0×10^{-2}/year. The analysis covered the risk affected by the performance deficiency for postulated fires of any of the nine normally closed breakers including the potential for one additional common cause fire initiator. The resulting change in core damage frequency (ΔCDF) was 1.1×10^{-4}. Additionally, seismically-induced fires were postulated based on the characteristics of the performance deficiency. The quantified ΔCDF for seismically-induced fires was 3.3×10^{-4}. Finally, the analyst determined that the finding did not involve a significant increase in the risk of a large, early release of radiation. The final result was calculated to be 4×10^{-4} indicating that the finding was of high safety significance (Red). Additional qualitative considerations suggest that the actual risk may be higher than this calculated value.

A detailed preliminary significance determination summary is attached.

2. All Other Inspection Findings

None.

D. Proposed Enforcement.

Region IV intends to issue a choice letter with Inspection Report 05000285/2011014 for the performance deficiency described above with three associated violations, preliminarily determined to be of high safety significance (Red). The violations are described below.

a. Regulatory requirement not met.

- 10 CFR Part 50, Appendix B, Criterion III, "Design Control."
- 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action."
- License Condition 3.D, "Fire Protection Program."

b. Proposed citation.

Three self-revealing violations were associated with this performance deficiency:

- A violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure to ensure that design changes were subject to design control measures commensurate with those applied to the original design; and, that measures were established to assure that applicable regulatory requirements and the design basis, for those safety-related structures, systems, and components were correctly translated into specifications, drawings, procedures, and instructions;

- A violation of 10 CFR Part 50, Appendix B, Criterion XVI "Corrective Action," for the failure to establish measures to assure that the cause of a significant condition adverse to quality was determined and corrective action taken to preclude repetition;

- A violation of License Condition 3.D, "Fire Protection Program," for the failure to ensure that the electrical protection and physical design of the 480 Vac electrical power distribution system provided the electrical bus separation required by the fire protection program.

Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part that: (1) design changes, including field changes, be subject to design control measures commensurate with those applied to the original design; (2) measures be established to assure that applicable regulatory requirements and the design basis for those safety-related structures, systems and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions; and (3) these measures shall include provisions to assure that appropriate quality standards are specified and included in design documents and that deviations from such standards are controlled.

Contrary to the above requirement, from November 2009 to June 7, 2011, the licensee failed to ensure that design changes were subject to design control measures commensurate with those applied to the original design; failed to assure that applicable regulatory requirements and the design basis for those safety-related structures, systems, and components to which this appendix applies were correctly translated into drawings, procedures, and instructions; and failed to ensure that these measures include provisions to assure that appropriate quality standards were specified and included in the design documents. Specifically, design reviews, work planning and instructions for a modification to install new 480 Vac load center breakers failed to ensure that the cradle adapter assemblies had low resistance connections with the switchgear bus bars by establishing a proper fit and requiring

low resistance measurements to assure that design basis requirements were maintained.

Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part that measures be established to assure that conditions adverse to quality such as failures, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.

Contrary to the above requirement, from May 22, 2008, to June 7, 2011, the licensee failed to assure that the case of the significant condition adverse to quality was determined and take corrective actions to preclude repetition. Specifically, the licensee failed to ensure that their preventative maintenance program for the safety-related 480 Vac electrical power distribution system was adequate to ensure proper cleaning of conductors, proper torquing of bolted conductor or bus bar connections, and adequate inspection for abnormal connection temperatures. In 2008, the licensee identified that preventative maintenance procedure EM-PM-EX-1200, "Inspection and Maintenance of Model AKD-5 Low Voltage Switchgear," was less than adequate as a result of a root cause analysis for the failure of bus-tie breaker BT-1B3A to close on demand and loss of bus 1B3A. The licensee categorized this failure as a significant condition adverse to quality. The analysis concluded, in part, that breaker BT-1B3A had high resistance connections, which occurred as a result of both procedure deficiencies and inadequate implementation, resulting in the failure to remove dirt and hardened grease from electrical contacts. The licensee implemented corrective actions to address these procedural deficiencies; however, the corrective actions were inadequate to prevent high resistance connections in load center 1B4A due to the presence of hardened grease and oxidation.

License Condition 3.D, "Fire Protection Program," requires, in part, that the licensee implement and maintain in effect all provisions of the approved Fire Protection Program as described in the Updated Safety Analysis Report (USAR) and as approved in NRC safety evaluation reports. Section 9.11.1 of the USAR describes the fire protection system design basis and states, in part, that the design basis of the fire protection systems includes commitments to 10 CFR 50, Appendix R, Sections III.G, III.J, and III.O. Section III.G, "Fire protection of safe shutdown capability," requires, in part, that fire protection features be provided for structures, systems, and components important to safe shutdown, and that these features be capable of limiting fire damage so that one train of systems necessary to achieve and maintain hot shutdown conditions is free of fire damage.

Contrary to the above requirement, from November 2009, to June 7, 2011, the licensee failed to implement and maintain in effect all provisions of the approved Fire Protection Program. Specifically, the licensee failed to ensure that design reviews for electrical protection and train separation of the 480 Vac electrical power distribution system were adequate to ensure that a fire in load center 1B4A would not adversely affect operation of redundant safe shutdown equipment in load center 1B3A, such that one train of systems necessary to achieve and maintain hot shutdown conditions were free of fire damage as required by the fire protection program. Combustion products from the fire in load center 1B4A migrated across normally open bus-tie breaker BT-1B4A into the non-segregated bus duct, shorting

all three electrical phases. The non-segregated bus ducting electrically connected load center 1B4A with the Island Bus 1B3A-4A and, through normally closed bus-tie breaker BT-1B3A, to the redundant safe shutdown train.

c. Historical precedent.

None.

E. Determination of Follow-up Review (as needed)

Per IMC 0609, NRR, and OE will review and concur with the final significance for all Red or Yellow findings.

PRELIMINARY PHASE 3 SIGNIFICANCE DETERMINATION
IMPROPER MODIFICATION/MAINTENANCE OF VITAL 480 VAC SWITCHGEAR

Analyst Assumptions

1. The Standardized Plant Analysis Risk Model for Fort Calhoun (SPAR), Revision 8.15, as modified by the analyst to include additional 480 Vac island buses and nonrecovery basic events for failure of 480 Vac load centers, was the best tool for quantifying the risk of the subject performance deficiency.

2. The SPAR, Revision 8.15 was modified to include 480 Vac Island Buses 1B3B-4B and 1B3C-4C including the appropriate mapping of safety functions supported by these buses.

3. The analyst assumed that, for this evaluation, basic events involving breaker failures for the nine 480 Vac normally-closed supply breakers plus the two 4160 Vac supply breakers and/or bus failures could be appropriately divided into a revised nominal failure rate and a nonrecovery whose product is equal to the original nominal failure rate as provided in Table 1.

Table 1
Revised/Additional Baseline Basic Events

Basic Event	Original	Revised	Nonrecovery BE	Value
ACP-CRB-CO-1B3A	3.6E-06	1.2E-05	ACP-BAC-1B3A-REC	3.0E-01
ACP-CRB-CO-1B3B	3.6E-06	1.2E-05	ACP-BAC-1B3B-REC	3.0E-01
ACP-CRB-CO-1B3C	3.6E-06	1.2E-05	ACP-BAC-1B3C-REC	3.0E-01
ACP-CRB-CO-1B4A	3.6E-06	1.2E-05	ACP-BAC-1B4A-REC	3.0E-01
ACP-CRB-CO-1B4B	3.6E-06	1.2E-05	ACP-BAC-1B4B-REC	3.0E-01
ACP-CRB-CO-1B4C	3.6E-06	1.2E-05	ACP-BAC-1B4C-REC	3.0E-01
ACP-CRB-CO-BT1B3A	3.6E-06	1.2E-05	ACP-BAC-1B3A4A-REC	3.0E-01
ACP-CRB-CO-BT1B3B	3.6E-06	1.2E-05	ACP-BAC-1B3B4B-REC	3.0E-01
ACP-CRB-CO-1BT1B3C	3.6E-06	1.2E-05	ACP-BAC-1B3C4C-REC	3.0E-01
ACP-BAC-LP-1A3	9.6E-06	2.2E-04	DIV-A-AC-REC	4.3E-02
ACP-BAC-LP-1A4	9.6E-06	2.2E-04	DIV-B-AC-REC	4.3E-02

4. The twelve subject breaker cubicles were modified in November 2009 and were in service from that point until the fire in June 2011.

5. Given that the reactor was in operation from November 2009 through April 2011, this finding is being evaluated as an at-power event because the failure was more likely to have occurred during power operations than at shutdown, and the failure mode was determined to be independent of plant or system operational mode.

6. Using best-available information, the inspectors concluded that the fire was caused by high-resistance connections between the cradle assembly and switchgear bus bars which resulted in overheating of the connections under

load. The deficient connections were a result of inadequate maintenance and/or modification.

7. Nine of the twelve 480 Vac supply breakers were closed for most of the time from November 2009 to June 2011.

8. The analyst evaluated the time frame over which the finding was reasonably known to have existed. The analyst determined that the breaker cubicles could have failed at any time from their installation in November 2009 until the failure in June, 2011, which was approximately 19 months.

9. In accordance with Manual Chapter 0609, Appendix A, Attachment 2, "Site Specific Risk-Informed Inspection Notebook Usage Rules," Rule 1.1, "Exposure Time," the analyst determined that the maximum exposure time used in the SDP should be used, which is limited to 1 year.

10. The inspectors noted that the Fire in Bus 1B4A caused the failure of Island Bus 1B3A-4A despite Breaker BT-1B4A being open. Therefore, the analyst assumed that any postulated fire in a 480 Vac load center with a normally-open tie breaker would cause the failure of its associated island bus.

11. The inspectors noted that all three island buses were physically located inside the switchgear containing the load center with the normally-closed tie breaker. One example is that Bus 1B3A is located in the same physical switchgear as Bus 1B3A-4A. Therefore, a hot gas layer would be free to communicate between cubicles in these switchgear. Therefore, analyst determined that any postulated fire in a 480 Vac load center with a normally-closed tie breaker would cause the failure of its associated island bus. Likewise, any postulated fire in a normally-closed tie breaker cradle would cause the failure of the associated load center.

12. During this time frame, a postulated failure of the breaker and/or cradle for these nine normally closed breakers would result in a fire that would cause severe damage to the bus, making the associated 480 Vac buses listed in Table 2 unrecoverable.

Table 2 Unrecoverable Bus Failures From Postulated Fires		
Fire Location	Buses Failed	
Breaker Cradle 1B3A	1B3A	1B3A-4A
Breaker Cradle 1B3B	1B3B	1B3B-4B
Breaker Cradle 1B3C	1B3C	1B3C-4C
Breaker Cradle 1B4A	1B4A	1B3A-4A
Breaker Cradle 1B4B	1B4B	1B3B-4B
Breaker Cradle 1B4C	1B4C	1B3C-4C
Breaker Cradle BT-1B3A	1B3A	1B3A-4A
Breaker Cradle BT-1B4B	1B4B	1B3B-4B
Breaker Cradle BT-1B3C	1B3C	1B3C-4C

13. The analyst determined that those buses documented under Assumption 12 as unrecoverable were not available for operation at any time during the mission times covered by the subject evaluation.

14. By plant procedures, both 480 Vac and 4160 Vac buses are de-energized in an effort to isolate electric power to the affected bus. Table 3 indicates the additional buses that would be de-energized by operators following a postulated fire.

Table 3 Buses De-energized Following Postulated Fires					
Fire Location	Buses De-energized				
Breaker Cradle 1B3A	1B3B	1B3C	1A3	1B3C-4C	
Breaker Cradle 1B3B	1B3A	1B3C	1A3	1B3C-4C	1B3A-4A
Breaker Cradle 1B3C	1B3A	1B3B	1A3	1B3A-4A	
Breaker Cradle 1B4A	1B4B	1B4C	1A4	1B3B-4B	
Breaker Cradle 1B4B	1B4A	1B4C	1A4		
Breaker Cradle 1B4C	1B4A	1B4B	1A4	1B3B-4B	
Breaker Cradle BT-1B3A	1B3B	1B3C	1A3	1B3C-4C	
Breaker Cradle BT-1B4B	1B4A	1B4C	1A4		
Breaker Cradle BT-1B3C	1B3A	1B3B	1A3	1B3A-4A	

15. Given the plant design of the normally open bus-tie breakers and the associated buswork, the smoke from a postulated fire in a 480 Vac load center with a normally-open bus-tie breaker will cause a fault in the nonsegregated bus resulting in the de-energization of the associated cross-train bus. Table 4 documents these additional buses that would be de-energized.

Table 4 Buses De-energized by Fire Faults From Postulated Fires	
Fire Location	Buses Failed
Breaker Cradle 1B3B	1B4B
Breaker Cradle 1B4A	1B3A
Breaker Cradle 1B4C	1B3C

16. The analyst assumed that the buses de-energized as documented under Assumptions 14 and 15 had the potential to be recovered prior to core damage, given appropriate operator action.

17. The breaker failure probability can be calculated by multiplying 1 failure of 9 breaker cradles that are normally subject to electrical load and dividing by the 19 months that they were in service.

18. In accordance with Abnormal Operating Procedure, AOP-06, "Fire Emergency," Revision 25, a fire in a vital 480 Vac load center requires operators to initially de-energize the associated 4160 Vac switchgear, opening all of the normally-closed breakers on that side of the ac power system.

19. The baseline core damage frequency was determined to be based on the frequency of an energetic fault in the most limiting fire scenario. The generic fire for vital switchgear from NRC Inspection Manual Chapter 0609, Appendix F, Attachment 4 is 4.70 x 10^{-6}/year. The smaller switchgear at Fort Calhoun Station have 5 vertical sections, resulting in an initiating event frequency of 2.4 x 10^{-5}/year. Therefore, as an example, the baseline risk for the postulated failure of Switchgear 1B4A, with a conditional core damage probability of 6.4 x 10^{-5}, will be 1.5 x 10^{-9}/year.

20. Following any of the fires postulated in Assumption 12 a reactor transient would occur, either directly from instrumentation and/or lost equipment or via licensed operators following plant procedures or required Technical Specifications.

21. Abnormal Operating Procedure, AOP-06, "Fire Emergency," Revision 25, directs operators to close and de-energize pressurizer power-operated relief valves and their associated block valves prior to de-energizing vital buses during a fire. As such, the analyst assumed that the pressurizer power-operated relief valves would not be available throughout the postulated event.

22. Technical Specification 2.7(2)f. permits one of the buses connected to Bus 1A3 or 1A4 to be inoperable for up to 8 hours. Technical Specification 2.7(2), "Modification of Minimum Requirements," requires that with Paragraph f not met:

> ". . . the reactor shall be placed in hot shutdown within the following 12 hours. If the violation is not corrected within an additional 12 hours, the reactor shall be placed in a cold shutdown condition within an additional 24 hours."

The analyst noted that licensed operators may decide to cool down the reactor more rapidly than required by Technical Specifications. However, many of the scenarios would require multiple manual system alignments to achieve cold shutdown presenting a potential that reactor cooldown timing would be limited more by manpower available than by license restrictions. Therefore, the analyst assumed that the reactor would be in a condition above cold shutdown for 56 hours following a postulated bus fire.

23. In lieu of a complex (while more traditional) common cause failure analysis, the analyst assumed that there was a potential for a second fire to initiate during the Technical Specification Allowed Outage Time and evaluated all potential two fire combinations. This was necessitated by both the frequency of a postulated fire and the consequences being too high to truncate.

24. The nonrecovery probability for restoration of buses that were manually de-energized during a postulated fire can be best quantified using the SPAR-H Method described in NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Method."

25. The operators, electricians and fire brigade personnel responding to the fire and the associated reactor event will be under high stress throughout the response. Therefore, all human reliability analysis would use high stress as a performance shaping factor in both the diagnosis and actions.

26. Given the need to ensure that the fire is extinguished and then to evacuate Halon and smoke products from the East and West Switchgear rooms following a postulated fire, the analyst reviewed the timing during the actual event. The space was not cleared, such that maintenance personnel could access the area, until almost 3 hours after the report of the fire. Therefore, the analyst determined that no recovery potential should be credited for core damage sequences lasting 2 hours or less.

27. Based on the need to ensure that all faults are properly isolated, the evolution of determining that a de-energized switchgear was capable of being energized again following a postulated fire was considered to be moderately complex. Therefore the diagnosis portion of this human reliability analysis should be increased.

28. Given the condition of Bus 1B4A following the fire, the analyst assumed that the smoke, soot coating of equipment, heat and lighting conditions in which operators and electricians would be locating, measuring and isolating all faults following any postulated fire in a 480 Vac bus would make these functions more difficult. Therefore, the ergonomics were considered to be poor for the diagnosis portion of the human reliability analysis.

29. The twelve 480 Vac supply breakers had a unique design requiring maintenance personnel to perform a local reset operation after a trip prior to reclosing the breaker. This delayed the operators in closing the breakers because of insufficient instructions to the operators, combined with a lack of familiarity with the design. Therefore, the analyst assumed that the procedures for the action portion of the human reliability analysis were poor.

30. A seismic event could result in the failure of the breaker/breaker cradle interface and/or bolted bus bars in a manner similar to the fire that occurred on June 7, 2011.

31. The failure discussed under Assumption 30 would occur with about the same fragility of the offsite power insulator stacks which represents the vibration levels that start to cause differential motion between uncoupled components.

32. Failures of more than two breaker cradles following a seismic event are possible. However, the evaluation of the risk for these scenarios would become prohibitive based on the large number of scenarios that would be possible and would not be expected to contribute significantly to the overall risk.

33. Once the plant is in cold shutdown, as required by Technical Specifications, the unavailability of two 480 Vac busses will continue to impact the risk of plant shutdown for several months while investigation and repairs are conducted.

34. The shutdown risk referred to under Assumption 33 is best evaluated in a qualitative manner for the subject significance determination.

35. The 480 Vac distribution system at Fort Calhoun Station supports the cooling of the spent fuel pool. As a result, the subject performance deficiency impacts the risk of core damage in the spent fuel pool. This risk is best evaluated in a qualitative manner for the subject significance determination.

36. While Assumption 8 describes a straight-line failure rate for the subject breaker cubicles, the actual failure frequency was most likely some form of an exponential curve. As such, the failure frequency would have been higher for the year of the exposure period than for the preceding 9 months. The additional risk associated with the higher failure rate is best evaluated in a qualitative manner for the subject significance determination.

37. For some fire scenarios, a fire in one bus will affect the dc control power for buses in the opposite train. As a result, manual operations of all breakers would be required for operator responses, increasing the risk associated with the finding. The additional risk resulting from the additional work load on operators responding to the postulated events is best evaluated in a qualitative manner for the subject significance determination.

38. Because during all postulated scenarios, one switchgear room would be inaccessible for 2-1/2 hours and the other would be filled with Halon making operator actions difficult and delayed, operators would not be able to strip

plant lighting loads within 15 minutes as required by plant procedures. The result would lead to vital battery depletion in approximately 2.6 hours.

Exposure Period

As stated in Assumptions 4, 7 and 8, the twelve subject breaker cubicles were modified in November 2009 and were in service from that point until the fire in June 2011. The analyst evaluated the time frame over which the finding was reasonably known to have existed. The analyst determined that the breaker cubicles could have failed at any time from their installation in November 2009 until the failure in June, 2011, which was approximately 19 months. The repair time for the failed buses continued as of December 2011.

As stated in Assumption 9, in accordance with Manual Chapter 0609, Appendix A, Attachment 2, "Site Specific Risk-Informed Inspection Notebook Usage Rules," Rule 1.1, "Exposure Time," the analyst determined that the maximum exposure time used in the SDP should be used, which is limited to 1 year.

Fire-Induced Risk

Fire Initiating Event Likelihood

As stated in Assumption 17, the breaker cubicle failure probability can be calculated by multiplying 1 failure of 9 breaker cradles and dividing by the 19 months that they were in service. Given that a breaker cubicle failure would result in catastrophic failure of the associated vital bus, the analyst calculated the initiating event likelihood (λ_{Fire}) as follows:

$$\lambda_{Fire} = \text{failures} \div (\text{breakers} * \text{months})$$

$$= 1 \div (9 \text{ breakers} * 19 \text{ months})$$

$$= 5.9 \times 10^{-3} \text{ /month} * 12 \text{ months/year}$$

$$= 7.0 \times 10^{-2} \text{ /year}$$

Safety Impact

As stated in Assumption 12, any postulated fire in one of the nine normally-closed breakers would result in the long-term failure of two vital 480 Vac buses. The risk-important equipment supplied by these buses would not be available throughout the accident sequences modeled and subsequent repair. Additionally, as stated in Assumptions 14 and 15, any postulated fire in one of the nine normally-closed breakers would result in operators de-energizing multiple additional vital buses and the potential de-energization of one additional bus caused by fire-related faults. The risk-important equipment supplied by those buses would not be available until the fire was extinguished, smoke and Halon removed from the switchgear rooms, plant personnel were capable of

determining that the buses were safe to re-energize, and operators re-energized the buses and reconnected the risk-important loads.

Application of Recovery

As stated in Assumptions 13 and 16, the potential for recovery of vital buses was grouped into the following categories:

1. The analyst determined that those buses documented under Assumption 12 as unrecoverable were damaged and not available for operation at any time during the 24 hour mission time (56 hours for two fire scenarios) covered by the subject evaluation.

2. The nonrecovery probability for restoration of undamaged 480 Vac buses de-energized by operators during a postulated fire were quantified using the SPAR-H Method described in NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Method." This analysis is documented in Table 5.

3. The nonrecovery probability for restoration of undamaged 480 Vac buses de-energized by fire-induced faults during a postulated fire were quantified using the SPAR-H Method described in NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Method." This analysis is documented in Table 5.

4. The nonrecovery probability for restoration of 4160 Vac buses de-energized by operators during a postulated fire were quantified using the SPAR-H Method described in NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Method." This analysis is documented in Table 6.

Table 5 Recovering 480 Vac Electrical Buses De-energized during Fire				
Performance Shaping Factor	**Diagnosis**		**Action**	
	PSF Level	**Multiplier**	**PSF Level**	**Multiplier**
Time:	Nominal	1.0	Nominal	1.0
Stress:	High	2.0	High	2.0
Complexity:	Moderately Complex	2.0	Nominal	1.0
Experience:	Nominal	1.0	Nominal	1.0
Procedures:	Nominal	1.0	Available, but Poor	5.0
Ergonomics:	Poor	10.0	Nominal	1.0
Fitness for Duty:	Nominal	1.0	Nominal	1.0
Work Processes:	Nominal	1.0	Nominal	1.0
	Nominal	1.0E-02		1.0E-03
	Adjusted	4.0E-01		2.0E-02
	Odds Ratio	2.9E-01		9.9E-03
	Composite	40		10
Failure to Re-energize 480 Vac Bus Following Fire Probability:				3.0E-01

Table 6 Recovering 4160 Vac Electrical Buses De-energized during Fire				
Performance Shaping Factor	**Diagnosis**		**Action**	
	PSF Level	**Multiplier**	**PSF Level**	**Multiplier**
Time:	Nominal	1.0	Nominal	1.0
Stress:	High	2.0	High	2.0
Complexity:	Moderately Complex	2.0	Nominal	1.0
Experience:	Nominal	1.0	Nominal	1.0
Procedures:	Nominal	1.0	Nominal	1.0
Ergonomics:	Nominal	1.0	Nominal	1.0
Fitness for Duty:	Nominal	1.0	Nominal	1.0
Work Processes:	Nominal	1.0	Nominal	1.0
	Nominal	1.0E-02		1.0E-03
	Adjusted	4.0E-02		2.0E-03
	Odds Ratio	3.9E-02		2.0E-03
	Composite	4		2
Failure to Reenergize 4160 Vac Bus Following Fire Probability:				4.1E-02

Adjustments to SPAR

The analyst noted that the results of the initial SPAR evaluation were more significant than both the licensee's evaluation and the risk-informed notebook. In reviewing these differences, it was noted that the licensee's model provided for recovery of auxiliary feedwater during a station blackout, following battery depletion. The licensee stated that Fort Calhoun Station had a unique arrangement for auxiliary feedwater. Auxiliary Feedwater Pump FW-54 is diesel driven and does not rely on vital ac or dc power. The pump is supplied with fuel from Diesel Fuel Oil Storage System Tank FO-10. Tank FO-10 has a minimum volume of 10,000 gallons of diesel fuel as required by Technical Specification 2.7. Eight thousand gallons of the tank's inventory are readily available for use by Pump FW-54. Therefore, the pump could run for 24 hours without fuel addition. The analyst noted that the condensate storage tank would provide about 30 hours of water based on licensee calculated steam generator steaming rates. Therefore, makeup water sources were not assessed.

Traditionally, SPAR methodology assumes that auxiliary feedwater fails upon loss of vital batteries. This failure assumes that instrumentation is lost and operators overfill the steam generators. Once the steam generators fill to the main steam lines, water flowing into the steam lines suppresses the steam supply to the turbine-driven pump. Given the postulated failure of the turbine-driven pump, the steam generators boil dry and the scenario leads to core damage. Providing a reliable diesel-driven pump resolves this problem, and the pump could theoretically continue to feed the steam generators for the 24-hour mission time.

To give credit for Pump FW-54, the failure mechanisms of the system, including the operator actions required to continue to feed the steam generators for 24 hours were evaluated. These included the following:

- Pump FW-54 must continue to run for 24 hours, including fuel supply, suction source, and the operator attention necessary.
- Operators must transfer the discharge of the system to the auxiliary feedwater nozzles and manually throttle discharge Valves HCV-11078 and HCV-11088 prior to battery depletion.
- Operators must ensure that there is sufficient auxiliary feedwater flow to prevent core damage.
- The reactor coolant pump seals must remain intact for 24 hours without vital ac or dc power. The analyst determined that the reactor coolant pump seals at Fort Calhoun Station were of the upgraded seal design. Therefore, the analyst utilized the value for the probability of seal failure during an extended loss of power, documented in the SPAR model. This value was 8.9×10^{-3}.
- Operators must isolate the condensate storage tank prior to loss of pressure in the associated nitrogen bottle. This action requires manual isolation of the hotwell supply line before the air-operated valve fails open and the condensate storage tank inventory is vacuum dragged to the condenser.
- Operators have a varying amount of time to perform these actions, depending on the success or failure of two operator actions:

  (1) operators minimize dc loads on the battery quickly following a station blackout and;
  (2) operators flood the steam generators to 94 percent wide-range level prior to battery depletion using either Pump FW-54 or the turbine-driven auxiliary feedwater pump.

The analyst used generic steam generator data and certain plant-specific information from the Final Safety Analysis Report to calculate the approximate time that operators would have to successfully operate Pump FW-54 following battery depletion conditional upon the success or failure of these two actions. Table 7 documents those times.

Table 7 Time to Steam Generator Dryout During Station Blackout					
Case	Minimize dc Loads	Time to Depletion	Flood Generators	Time for Boil Down	Total Time
1	Success	8 hours	Success	5 hours	13 hours
2	Success	8 hours	Failure	2.6 hours	10.6 hours
3	Failure	2.6 hours	Success	4 hours	6.6 hours
4	Failure	2.6 hours	Failure	2 hours	4.6 hours

The analyst quantified the probability that the operators fail to minimize dc loads in a short period of time using the SPAR-H method described in NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Method." The procedural requirements in Emergency Operating Procedure EOP-00, "Standard Post Trip Actions," and Emergency Operating Procedure Attachment 6, "Minimizing DC Loads," were evaluated. The analyst assumed that this particular action did not require a significant amount of diagnosis because the EOP-00 has a step and multiple notes reminding the operators to take the action when necessary. The analyst adjusted the nominal human error probabilities using the following performance shaping factors:

- Available time was 15 minutes. The analyst assumed that this was just enough time to coordinate with two plant operators and to open breakers in the turbine building and the auxiliary building. Therefore, a factor of 10 was used.

- The stress was assumed to be high because of an ongoing station blackout. Therefore, a factor of 2 was used.

- The complexity was assumed to be moderate because of the coordination needed with plant operators at two different locations and the low lighting during the station blackout conditions. Therefore, a factor of 2 was used.

In addition to these three shaping factors, the analyst adjusted the final result using the Odd's ratio[1] as documented in the draft NUREG, Section 2.5. The probability that operators would fail to minimize dc loads within 15 minutes of a station blackout was calculated to be 3.9×10^{-2}. NOTE: This value was used in calculating the baseline risk of the condition. However, as stated in Assumption 38, the analyst determined that operators would fail to minimize dc loads.

Using a similar approach, the analyst calculated probabilities of human error for each of the required operator actions listed above. The times available, documented in Table 8, were used to modify the performance shaping factors

[1] Odd's ratio is a method of accounting for the number of successes as well as failures when calculating a conditional human error probability. This method of accounting for uncertainties associated with individual performance shaping factors is described in NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Method," and tends to provide a less conservative result.

based on the time operators had to respond to the particular action. The HRA values calculated are documented in Table 8.

Table 8
Operator Failure Probabilities

		Performance Shaping Factors				
Operator Action	Time Available	Time	Stress	Procedure	Experience	Failure Probability
Minimize dc Loads [8, 9]	15 minutes	10	2.0	1.0	1.0	3.9×10^{-2}
Flood S/Gs to 94% [4,9]	2.6 hours	1.0	2.0	1.0	0.5	1.0×10^{-3}
	8 hours	0.1	2.0	1.0	0.5	1.0×10^{-4}
Swap to AFW nozzle and throttle AFW Valves [3,8]	<3 hours	1.0	1.0/2.0[2]	0.5/2.0[5]	1.0/3.0[7]	3.8×10^{-1}
	>4.5 hours	0.1	1.0/2.0[2]	0.5/2.0[5]	1.0/3.0[7]	5.7×10^{-2}
Provide Sufficient Flow [4,9]	2 – 8 hours	0.1	2.0	0.5	1.0	1.0×10^{-4}
Isolate CST [4]	4 hours	1.0/0.1[1]	2.0	0.5/1.0[6]	1.0	1.2×10^{-3}

Notes:

[1] Nominal time was available for diagnosis, but there was barely adequate time to take the action.

[2] Nominal stress was used for diagnosis because of control room environment and verbatim emergency operating procedure compliance. High stress in the field because actions would affect plant safety.

[3] The following items also had the Complexity PSF changed to 0.1 for an obvious diagnosis, and 2.0 for a moderately complex action: minimize dc loads and swap to AFW nozzles.

[4] Complexity values adjusted to indicate an obvious diagnosis based on emergency operating procedure review.

[5] The procedures for diagnosing the need for this step were symptom based, but the procedures for implementation were considered by the analyst to be poor.

[6] The procedures for diagnosing the need for this step were symptom based, but the procedures for implementation were considered by the analyst to be nominal.

[7] The experience of operators is nominal for diagnosing this need, but they do not routinely operate the valve gags in this situation.

[8] The ergonomics were considered poor for swapping the AFW nozzle because an unfamiliar task would have to be done without normal lighting.

[9] These actions did not include a significant amount of diagnosis. Therefore, only the action failure probability was calculated.

The analyst created an event tree to model the actions required to successfully use Pump FW-54 following battery depletion. This event tree, provided as Attachment 1 to this analysis, covered each of the functions required to achieve success, as well as the probability that actions affecting the time available (i.e., minimizing dc loads) would be completed. The analyst used the SPAR to quantify Fault Tree AFW-FW54, "Fort Calhoun PWR G AFW FW-54," and provide a probability that the Pump FW-54 train would fail from stochastic reasons at any time during the accident sequence. The probability of failure was determined to be 3.1×10^{-2}. The analyst then quantified the event tree using the human reliability values listed in Table 8 and the solution from the SPAR fault tree for Pump FW-54 as split fractions. This quantification provided the total failure probability of the Pump FW-54 train during an unrecovered station blackout, upon depletion of the station vital batteries. The probability was quantified as 1.1×10^{-1}.

Given Assumption 38, the depletion of station batteries would take place at 2.6 hours. Therefore, in the event tree in Attachment 1, the Top Event, "Minimize-D," was always failed. The analyst requantified the event tree and determined that the total nonrecovery probability was 4.0×10^{-1} for most cutsets.

The analyst modified the SPAR model to include the attached Event Tree, "FW54 Cooling Following Battery Depletion." The analyst created a transfer to this tree from Event Tree, "Fort Calhoun PWR G Transient," for Sequences 13, 14, and 15.

Treatment of Common Cause Component Failure Probability

Given the unique sets of buses affected by any given postulated fire and the independence of the fire initiators, the analyst determined that the classic alpha-factor method was not appropriate to evaluate the common cause failure probability for the nine vital 480 Vac buses associated with the performance deficiency. As such, in lieu of classical treatment, the analyst quantified the potential that a second independent fire occurs during the time that the plant would likely be maintained above cold shutdown.

As stated in Assumptions 22 and 23, the analyst determined that any postulated independent second fire that occurred within 56 hours (Overlap Time) of the first should be evaluated in combination with the first as an at-power event. Therefore, the analyst calculated the conditional probability that overlapping fires would impact the at-power risk ($P_{Overlap}$) as follows:

$$P_{Overlap} = \text{Overlap Time} * \lambda_{Fire}$$

$$= 56 \text{ hours} \div 8760 \text{ hours/year} * 7.0 \times 10^{-2} \text{ /year}$$

$$= 4.5 \times 10^{-4}$$

Quantification of Conditional Core Damage Probabilities

As stated in Assumptions 1, 2, and 3, the analyst created a more detailed model of the electrical distribution system than that provided in the Fort Calhoun SPAR, Revision 8.15. The changes included appropriate mapping of risk-significance plant equipment and functions supported by these buses. Idaho National Laboratories assisted in incorporating these changes into the SPAR model and validating the impact. The analyst calculated the change in risk related to this performance deficiency using the following method:

The analyst quantified the new model and reestablished a baseline risk for:

Internal Core Damage Frequency	9.3×10^{-6} /year
Single Energetic Switchgear Fire CDF	1.5×10^{-9} /year
Seismically-Induced LOOP CCDP	1.2×10^{-3}

For each of the postulated fires documented in Assumptions 12 and 23 the analyst set the failure probability of the associated vital buses and/or supply breakers to 1.0. Table 10 provides the change sets used for each postulated fire.

The analyst quantified the conditional core damage probability for each of the nine postulated fires. The results are provided in Table 9.

Table 9
Conditional Core Damage Probabilities

Postulated Fire:	Case CCDP:
1B4A	6.4E-05
1B3A	3.1E-05
1B3B	6.1E-05
1B3C	5.8E-05
1B4B	2.3E-05
1B4C	3.8E-05
1B3A-4A	3.1E-05
1B3B-4B	2.3E-05
1B3C-4C	5.8E-05

The analyst then quantified the conditional core damage probability for each combination of two breaker cubicle fires. As stated in Assumption 23, these independently-initiated fires are being evaluated in lieu of a more complex common cause failure evaluation. These results are documented in Table 11.

Table 10

Affected Basic Events for Each of Nine Postulated Fires

Breaker 1B4A	Breakers 1B4B or BT-1B4B	Breaker 1B4C	Breakers 1B3A or BT-1B3A	Breaker 1B3B	Breakers 1B3C Or BT-1B3C
ACP-BAC-LP-1B4A	ACP-BAC-LP-1B4B	ACP-BAC-LP-1B4C	ACP-BAC-LP-1B3A	ACP-BAC-LP-1B3B	ACP-BAC-LP-1B3C
ACP-BAC-LP-1B3A4A	ACP-BAC-LP-1B3B4B	ACP-BAC-LP-1B3C4C	ACP-BAC-LP-BT1B3A	ACP-BAC-LP-1B3B4B	ACP-BAC-LP-1B3C4C
ACP-CRB-CO-1B3A	ACP-CRB-CO-1B4A	ACP-CRB-CO-1B4A	ACP-CRB-CO-1B3B	ACP-CRB-CO-1B3A	ACP-CRB-CO-1B3A
ACP-CRB-CO-1B4B	ACP-CRB-CO-1B4C	ACP-CRB-CO-1B4B	ACP-CRB-CO-1B3C	ACP-CRB-CO-1B3C	ACP-CRB-CO-1B3B
ACP-CRB-CO-1B4C	ACP-BAC-LP-1A4	ACP-CRB-CO-1B3C	ACP-CRB-CO-1BT1B3C	ACP-CRB-CO-1B4B	ACP-CRB-CO-BT1B3A
ACP-CRB-CO-BT1B3B		ACP-CRB-CO-BT1B3B	ACP-BAC-LP-1A3	ACP-CRB-CO-BT1B3A	ACP-BAC-LP-1A3
ACP-BAC-LP-1A4		ACP-BAC-LP-1A4		ACP-CRB-CO-1BT1B3C	
				ACP-BAC-LP-1A3	

Table 11

Combinations of 2 Fires - Conditional Core Damage Probability

	1B4A	1B3A	1B3B	1B3C	1B4B	1B4C	1B3A-4A	1B3B-4B	1B3C-4C
1B4A		7.4E-02	1.9E-01	1.8E-01	8.4E-05	1.7E-04	7.4E-02	8.4E-05	1.8E-01
1B3A	7.4E-02		8.0E-05	7.1E-05	2.6E-02	2.6E-02		2.6E-02	7.1E-05
1B3B	1.9E-01	8.0E-05		2.5E-04	6.7E-02	6.8E-02	8.0E-05	6.7E-02	2.5E-04
1B3C	1.8E-01	7.1E-05	2.5E-04		6.1E-02	7.7E-02	7.1E-05	6.1E-02	
1B4B	8.4E-05	2.6E-02	6.7E-02	6.1E-02		4.0E-05	2.6E-02		6.1E-02
1B4C	1.7E-04	2.6E-02	6.8E-02	7.7E-02	4.0E-05		2.6E-02	4.0E-05	7.7E-02
1B3A-4A			8.0E-05	7.1E-05	2.6E-02	2.6E-02		2.6E-02	7.1E-05
1B3B-4B	8.4E-05	2.6E-02		6.1E-02		4.0E-05	2.6E-02		2.5E-04
1B3C-4C	1.8E-01	7.1E-05	2.5E-04		6.1E-02		7.1E-05	2.5E-04	

Table 12

Change in Core Damage Frequency for Single Postulated Fires

Postulated Fire:	Exposure Period (days)	Failure Frequency (/year)	Case CCDP	ICCDP
1B4A	365	7.0E-02	6.4E-05	4.5E-06
1B3A	365	7.0E-02	3.1E-05	2.1E-06
1B3B	365	7.0E-02	6.1E-05	4.3E-06
1B3C	365	7.0E-02	5.8E-05	4.1E-06
1B4B	365	7.0E-02	2.3E-05	1.6E-06
1B4C	365	7.0E-02	3.8E-05	2.7E-06
1B3A-4A	365	7.0E-02	3.1E-05	2.1E-06
1B3B-4B	365	7.0E-02	2.3E-05	1.6E-06
1B3C-4C	365	7.0E-02	5.8E-05	4.1E-06

Calculation of Change in Core Damage Frequency

The analyst calculated the change in core damage frequency for each postulated fire as documented in Table 12. The sum of the change in core damage frequencies, 2.7×10^{-5}, is the best estimation of the fire-induced risk for single fire scenarios caused by the subject performance deficiency.

The analyst calculated the change in core damage frequency for each of the 63 postulated fire combinations documented in Table 11. The sum of the change in core damage frequencies, 8.1×10^{-5}, is the best estimation of the fire-induced risk for multiple fire scenarios caused by the subject performance deficiency. Although there is some overlap in the quantification of single and multiple fires, the analyst determined that this dependence was negligible in the final result.

The sum of the fire-induced change in core damage frequencies is 1.1×10^{-4}.

Seismically-Induced Risk

The analyst determined that, for the subject performance deficiency to affect the core damage frequency related to seismic events, the event must result in a fire in at least one of the nine normally-closed 480 Vac breakers. The analyst noted that the dominant risk would result when the seismic event was large enough to result in a loss of offsite power from failure of the switchyard insulators. Additionally, to quantify the increase in core damage frequency (ΔCDF) caused by the inadequately modified/maintained 480 Vac switchgear, the analyst must know the probability that combinations of 480 Vac buses would fail as a result of the performance deficiency, as well as the change in core damage probability assuming that the above postulated conditions occurred.

As such, the analyst evaluated the subject performance deficiency by determining each of the following parameters for any seismic event producing a given range of median acceleration "a" [SE(a)]:

1. The frequency of the seismic event SE(a) ($\lambda_{SE(a)}$) ;
2. The probability that a LOOP occurs during the event ($P_{LOOP\text{-}SE(a)}$);
3. The probability that a given combination of buses fail during the event ($P_{Bus\text{-}SE(a)}$);
4. The number of combinations to be analyzed (Comb);
5. The baseline core damage probability ($CCDP_{SE(a)}$); and
6. The sum of the conditional core damage probabilities ($\Sigma\Delta CCDP_{Bus\text{-}SE(a)}$)

The ΔCDF for the acceleration range in question ($\Delta CDF_{SE(a)}$) can then be quantified as follows:

$$\Delta CDF_{SE(a)} = \lambda_{SE(a)} * P_{LOOP\text{-}SE(a)} * P_{Bus\text{-}SE(a)} * (\Sigma\Delta CCDP_{Bus\text{-}SE(a)} - (Comb * CCDP_{SE(a)}))$$

Given that each range "a" was selected by the analyst specifically to be independent of all other ranges, the total increase in risk, ΔCDF, can be quantified by summing the $\Delta CDF_{SE(a)}$ for each range evaluated as follows:

$$\Delta CDF = \sum_{a=.05}^{8} \Delta CDF_{SE(a)}$$

over the range of SE(a).

Frequency of the Seismic Event

NRC research data indicates that seismic events of 0.05g or less have little to no impact on internal plant equipment. Therefore, the analyst assumed that seismic events less than 0.05g do not directly affect the plant. The analyst assumed that seismic events greater than 8.0g lead to core damage. The analyst, therefore, examined seismic events in the range of 0.05g to 8.0g.

The analyst divided that range of seismic events into segments (called "bins" hereafter). Specifically, seismic events from 0.05-0.08g, 0.08-0.15g, 0.15-0.25g, 0.25-0.30g, 0.30-0.40g, 0.40-0.50g, 0.50-0.65g, 0.65-0.80g, 0.80-1.0g, and 1.0-8.0g defined each bin. These bins were selected from the published hazard curve for the Fort Calhoun Station at frequencies presumed to affect plant equipment differently.

In order to determine the frequency of a seismic event for a specific range of ground motion (g in peak ground acceleration), the analyst used the Risk Assessment of Operation Events (RASP) Handbook, Volume 2, "External Events," and obtained values for the frequency of the seismic event that generates a level of ground motion that exceeds the lower value in each of the bins. The analyst then calculated the difference in these "frequency of exceedance" values to obtain the frequency of seismic events for the binned seismic event ranges.

For example, according to the RASP, the frequency of exceedance for a 0.08g seismic event at Fort Calhoun Station is estimated at 5.6 x 10^{-4}/yr and a 0.15g seismic event at 2.3 x 10^{-4}/yr. The frequency of seismic events with median acceleration in the range of 0.08g to 0.15g [$SE_{(0.08-0.15)}$] equals the difference, or 3.2 x 10^{-4}/yr.

Probability of a Loss of Offsite Power

The analyst assumed that a seismic event severe enough to break the ceramic insulators on the transmission lines will cause an unrecoverable loss of offsite power.

The analyst obtained data on switchyard components from the Risk Assessment of Operating Events Handbook; Volume 2, "External Events," Revision 4, which referenced generic fragility values listed in:

> NUREG/CR-6544, "Methodology for Analyzing Precursors to Earthquake-Initiated and Fire-Initiated Accident Sequences," April 1998; and
>
> NUREG/CR-4550, Vols 3 and 4 part 3, "Analysis of Core Damage Frequency: Surry / Peach Bottom," 1986

The references describe the mean failure probability for various equipment using the following equation:

$$P_{fail(a)} = \Phi\, [\, \ln(a/a_m) \,/\, (\beta_r^2 + \beta_u^2)^{1/2}]$$

Where Φ is the standard normal cumulative distribution function and

a = median acceleration level of the seismic event;
a_m= median of the component fragility;
β_r= logarithmic standard deviation representing random uncertainty;
β_u= logarithmic standard deviation representing systematic or modeling uncertainty.

In order to calculate the LOOP probability given a seismic event the analyst used the following generic seismic fragilities:

$a_m = 0.3g$
$\beta_r = 0.30$
$\beta_u = 0.45$

Using the above normal cumulative distribution function equation the analyst determined the conditional probability of a LOOP given a seismic event. For each of the bins the calculation was performed substituting for the variable "a" (peak ground acceleration) the acceleration levels obtained from the bins described above. Table 13 shows the results of the calculation for various acceleration levels.

Table 13 Peak Ground Acceleration/Probability of LOOP								
0.05g	2.0E-3		0.3g	6.0E-1		0.8g	9.8E-1
0.15g	2.1E-1		0.5g	8.8E-1			

Given Assumptions 30 and 31, the independent probability that any given breaker cubicle would fail within an associated bin would be equal to the probability of a LOOP. Continuing this logic, the failure probability of any two breaker cubicles would be the square of the conditional LOOP probability for the bin.

Conditional Change in Core Damage Probability

The analyst evaluated the spectrum of seismic initiators to determine the resultant impact on the reliability and availability of mitigating systems affecting the subject performance deficiency.

The analyst used the Fort Calhoun Station Revision 8.15 SPAR Model (as modified), to perform the evaluations. The analyst first created a baseline case by setting the initiating event probability for a LOOP to 1.0 and all other initiating event probabilities in the SPAR model to zero. Offsite power was assumed to be

nonrecoverable following seismic events that break the ceramic insulators (low fragility components) on the transmission lines. Therefore, the analyst set the nonrecovery probabilities for offsite power to 1.0. The modified SPAR model quantified the resultant conditional core damage frequency as 1.2×10^{-3}, which represented the baseline case that is used in the above equation.

The SPAR Model was then used to quantify the case values using the change sets described in Table 10. The change in conditional core damage probability was calculated for each postulated single fire within each bin and for each combination of two fires designated in Table 11. The analyst noted that the seismic failure of multiple breakers would be a likely scenario. However, these were not evaluated given the significant amount of effort required to perform such calculations and that the change in core damage frequency for postulated single seismically-induced fires already exceeded the Yellow/Red Threshold.

Phase 3 Seismic Results

Considering the factors described above for each bin, namely,

- The frequency of the seismic event;
- The probability that a LOOP occurs during the event;
- The probability that a given vital bus would fail during the event;
- The baseline core damage probability; and
- The conditional core damage probabilities

The total increase in seismically-induced risk, $\Delta CDF_{Seismic}$, can be quantified by summing the $\Delta CDF_{SE(a)}$ for each bin as follows:

$$\Delta CDF = \sum_{a=.05}^{8} \Delta CDF_{SE(a)}$$

Given the assumptions, the total increase in core damage frequency was estimated to be about 2.9×10^{-4} from single and double initiated fires for seismic events ranging from 0.05g to 8.0g.

High Winds, Floods, and Other External Events

The analyst reviewed the licensee's Individual Plant Examination of External Events and determined that no other credible scenarios initiated by high winds, floods, fire, and other external events could initiate a failure of the subject breaker cubicles. Therefore, the analyst concluded that external events other than fires initiated by the performance deficiency and/or seismic events are not significant contributors to risk for this finding.

Large Early Release Frequency

In accordance with the guidance in NRC Inspection Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process," this finding would not involve a significant increase in risk of a large, early release of radiation because Fort Calhoun has a large, dry containment and the dominant

sequences contributing to the change in the core damage frequency did not involve either a steam generator tube rupture or an inter-system loss of coolant accident.

Qualitative Considerations of Risk

The analyst noted that several factors that affected the risk of the subject postulated fires were not quantified because practical matters made them significantly more difficult to quantify. They included the following:

1. Shutdown Risk

   As documented in Assumptions 33 and 34, the analyst noted that additional risk would be accumulated at the plant following the fires postulated in this analysis. 480 Vac loads at Fort Calhoun Station include component cooling water, containment spray, spent fuel pool cooling and other support systems necessary for maintaining the reactor and/or spent fuel pool cool during shutdown conditions.

   The long-lasting effects of a major fire continue to impact plant operations and require additional operator actions throughout the shutdown period while the bus or buses are being repaired. Additionally, a loss of shutdown cooling during critical shutdown conditions as a result of a postulated fire would cause significant increase in the instantaneous risk of the shutdown reactor.

   The analyst determined that these impacts were too numerous to individually identify and the current shutdown risk tools do not lend themselves to assess the impacts quantitatively. However, the analyst noted that these risks should be considered in making a risk-informed decision.

   To estimate the impact of this risk, the analyst evaluated the impact of loss of component cooling water pumps from postulated 480 volt bus fires. The following assumptions were made:

   a. The impact on Component Cooling Water would be 98 days. This was based on the bus fire occurring on June 7 and the licensee declaring the remaining buses inoperable on September 13.
   b. The results from the San Onofre Shutdown SPAR model were good enough to approximate this risk, given that the vast majority of risk impact was the result of human error and not additional equipment failures.
   c. Each postulated fire scenario that affected one or more component cooling water pumps were quantified.

   The estimated incremental conditional core damage probability was 6.9×10^{-5}. The analyst determined that this value was not accurate enough to meet the quantitative requirements of the significance determination process. However, the actual probability would be added to the final risk determination were it known accurately. This indicates

that shutdown risk during the repair time following a postulated fire would be significant with respect to the subject finding.

2. Seismic Risk from 3 or More Postulated Fires

As documented in Assumption 32, failures of more than two breaker cradles following a seismic event are possible. However, the evaluation of the risk for these scenarios would become prohibitive based on the large number of scenarios that would be possible and would not be expected to contribute significantly to the overall risk.

The analyst noted that the addition of multiple fire scenarios can add combinations that result in conditional core damage probabilities of 1.0, losses of residual heat removal at shutdown, complete losses of spent fuel pool cooling, as well as failures of all higher pressure injection capability.

As stated above, the analyst determined that these impacts were too numerous and prohibitive to individually evaluate quantitatively. However, the analyst noted that these risks should be considered in making a risk-informed decision.

To better understand the risk of this contributor, the analyst evaluated the range of risk impact for a seismic event causing three breaker cubicle fires. The analyst utilized the modified SPAR model to determine the risk of fires involving Buses 1B3A, 1B3B, and 1B3C-4C. This was considered to be the lowest possible risk from a combination of 3 fires. The conditional core damage probability for these fires was 7.27×10^{-2}. The analyst then quantified the conditional core damage probability for postulated fires in Buses 1B4A, 1B3B, and 1B3C-4C. This combination resulting in the highest possible risk was quantified as 1.0.

The analyst then performed a seismic evaluation assuming that all fires evaluated resulted in the conditional core damage probabilities listed above. This resulted in a range of 3.4×10^{-5} to 4.7×10^{-4}. The analyst noted that neither the low end nor the high could be the result, but only that the result would lay somewhere between the two. This risk would be additive to the best estimate value indicating that the risk from a seismic event causing three or more breaker cubicle failures would be significant with respect to the subject finding.

3. Risk to Fuel in the Spent Fuel Pool

As documented in Assumption 35, the 480 Vac system at Fort Calhoun Station supports the cooling of the spent fuel pool. As a result, the subject performance deficiency impacts the risk of core damage in the spent fuel pool. As few as two postulated fires could result in the complete loss of plant process equipment designed to cool the spent fuel pool.

The current risk tools available to the analyst do not lend themselves to assess the impacts of a loss of spent fuel pool cooling quantitatively. However, the analyst noted that these risks should be considered in making a risk-informed decision.

The analyst noted that the risk to the spent fuel pool would be substantially less than that for the shutdown reactor. This is primarily because of the capability to feed and bleed the pool and the acceptability of almost any water source. Therefore, while this risk would be additive, it would not be significant to the subject evaluation.

4. <u>Potential Loss of Control Power</u>

As stated in Assumption 37, for some fire scenarios, a fire in one bus will affect the dc control power for buses in the opposite train. For example, a fire in Bus 1B3B would likely destroy Manual Transfer Switch 1B3B-4B-MTS. This switch controls dc power to Buses 1B4A, 1B4B, 1B3B-4B, and 1B4C. Loss of control power to these buses will, at a minimum, require local manual operation of all the automatic circuit breakers, including feeder breakers and bus-tie breakers. Also, this failure would likely impact the undervoltage relays on the 480 buses and might impact the indicator functionality.

As a result, manual operations of all breakers would be required for operator responses, increasing the risk associated with the finding. The analyst noted that the current SPAR model does not include individual switches and load breakers, nor does it map the effects of dc control power. However, there is additional risk resulting from the extra work load on operators responding to the postulated events that was not calculated in this evaluation. However, the analyst noted that these risks should be considered in making a risk-informed decision.

To better understand the potential impact of this factor, the analyst reran the worst case fire scenario using twice the nonrecovery terms. The increase in risk was less than twice the original conditional core damage probability. Therefore, while this risk would be additive, it would not be significant to the subject evaluation.

5. <u>Calculation of Breaker Cubicle Failure Rate</u>

As stated in Assumption 36, the failure frequency was calculated as a straight-line rate for the subject breaker cubicles. However, the actual failure frequency was most likely some form of an exponential curve. As such, the failure frequency for the last few months of the exposure period would have been higher than the average failure frequency as calculated. The quantified risk is proportional to the failure rate. Therefore, the risk is likely higher and may be substantially higher than quantified.

Because the actual slope of the failure rate curve is unknown, the additional risk resulting from the approximated failure rate could not be

quantified. However, the analyst noted that these risks should be considered in making a risk-informed decision.

To better understand the risk of this contributor, the analyst evaluated the result given a failure rate that was twice the calculated rate with 1/4 the total exposure time. The resulting total incremental conditional core damage probability was 3.4×10^{-4}. Being 3 times the best estimate value for independent fires, this indicated that, if the failure frequency could be quantified as a decaying rate, the results would be significant with respect to the subject finding.

Sensitivities

The analyst performed a sensitivity study for two of the dominant assumptions in this evaluation. The following assessments were conducted:

1. Assumptions 30 and 31 indicate that the subject performance deficiency could be affected by seismic activity and an approximate seismic fragility at which a breaker cradle would fail. The analyst reevaluated the risk given the following three changes to these assumptions:

    a. Breaker cradles would fail with a fragility similar to the generic functional failure of electrical components from chatter (approximately 1.0g pga);

    b. Breaker cradles would not fail from a seismic event; and

    c. Breaker cradles would fail upon a seismically induced loss of coolant accident.

2. Assumptions 22 and 23 indicate that two independent fires could occur at times close enough to impact the risk of the at-power plant. The fundamental assumption provided that the frequency of these fires would be evaluated over a 56-hour period. The analyst reevaluated the risk of these two fire scenarios given a 24-hour period and a 72-hour period.

The results of this sensitivity analysis are provided in Table 14.

Table 14
Results of Sensitivity Studies

Change Evaluated	Incremental Conditional Core Damage Probability		
	Independent Fire	Seismic	Total
Best Estimate Seismic Analysis	1.1×10^{-4}	3.3×10^{-4}	[redacted]
Nominal Chatter Functional Failure		6.1×10^{-5}	[redacted]
No Seismic Failure		0.0	[redacted]
Failure upon Seismic LOOP		8.1×10^{-4}	[redacted]
Two fires in 56 hours (Best Estimate)	1.1×10^{-4}		[redacted]
Two fires in 24 hours	6.2×10^{-5}		[redacted]
Two fires in 72 hours	1.5×10^{-4}		[redacted]
Highest Combination	1.5×10^{-4}	8.1×10^{-4}	[redacted]
Lowest Combination	6.2×10^{-5}	0.0	6.2×10^{-5}

Conclusions

The senior reactor analyst completed a Phase 3 analysis using the plant-specific Standardized Plant Analysis Risk Model for Fort Calhoun, Revision 3.45, the licensee's Individual Plant Examination of External Events, and hand calculations. The exposure period of 1 year represented the maximum exposure time allowable in the significance determination process. The analyst estimated the initiating event likelihood for a single fire of 7.0×10^{-2}/year. The analysis covered the risk affected by the performance deficiency for postulated fires of any of the nine normally-closed breakers including the potential for two independent fire initiators. The resulting change in core damage frequency (ΔCDF) was 1.1×10^{-4}. Additionally, seismically-induced fires were postulated based on the characteristics of the performance deficiency. The quantified ΔCDF for seismically-induced fires was 3.3×10^{-4}.

Finally, the analyst determined that the finding did not involve a significant increase in the risk of a large, early release of radiation. The final result was calculated to be 4×10^{-4} indicating that the finding was of high safety significance (Red).

The analyst performed sensitivity studies indicating that only the most negative combination of assumption changes provided a value in the Yellow region. 95.7 percent of the risk range from these sensitivities was in the Red region. Additionally, qualitative considerations suggest that the actual risk is higher than this calculated value, and could be Red of their own right if properly quantified.

Licensee's Proposed Modeling Assumptions

To facilitate better communications on this evaluation, the licensee provided the analyst with a set of proposed modeling assumptions (draft) dated November 14, 2011. The analyst reviewed the licensee's assumptions to ensure that

appropriate treatment was considered. The following addresses each of the licensee's draft assumptions and how they were dispositioned:

1. The licensee assumed that potential breaker fire consequences should be modeled for the nine normally-closed 480V breakers that were modified in 2009.

   We agree. This is documented in Assumptions 7 and 12.

2. The licensee reserved the right to challenge the fire frequency. They stated that not just Fort Calhoun, but any applicable industry data should be used.

   We agree. However, neither the licensee nor our analysts have found any additional data. Additionally, the frequency is probably not linear, so we could potentially justify an even higher failure rate for the year assessed.

   The licensee informed us on January 12, 2012, that they were unable to identify additional data applicable to this finding.

3. The licensee assumed that the exposure time should be 1 year and evaluated for at-power operation.

   We agree. This is documented in Assumptions 5, 8 and 9.

4. The licensee stated that the total mission time should be 24 hours. This is opposed to our Assumptions 22 and 23.

   We disagree. While 24 hours is a classical mission time and was used for the actual fire response equipment, Assumption 23 clearly states that the 56 hours is used in an attempt to better quantify the common cause failure probability. The licensee did not suggest a different method for applying common cause. However, it is clear that common cause factors were in play.

   During a January 12, 2012 phone call with the licensee's PRA group, we agreed to disagree on this issue.

5. The licensee assumed that postulated fires of the bus main breaker or bus-tie breaker would result in failure of the adjacent bus or buses. Also, a 480 Vac main bus breaker fire adjacent to a normally-open bus tie breaker was assumed to induce a fault on the island-bus side of the normally-open bus tie breaker and induce a trip of the opposite main bus breaker.

   We agree with the licensee's definitions of which buses would fail and which would be tripped, as documented in Assumptions 12 through 15.

   However, their analyst assumed that cross-tie capability could be used to restore buses to power. The NRC analyst noted that conditions would not

permit operators to simply close a breaker following tripping it to extinguish a fire. Therefore, the probability of having a bus available is much lower than nominal. Additionally, the analyst determined that most of the core damage sequences included a loss of opposite train power. Given a loss of power on the opposite train, power cannot be restored to the switchgear by cross tying the buses.

During a January 12, 2012 phone call with the licensee's PRA group, they stated that their modeling the cross-tie capability did not significantly decrease the calculated risk of this finding. Therefore, the analyst's concern was alleviated and the NRC did not model the bus cross-ties.

6. The licensee assumed that, following a postulated fire;

   a. Block valves would be closed
   b. Reactor would be manually tripped
   c. The associated 4160 Vac buses would be de-energized

   The licensee stated that individual supply breakers may or may not be tripped and that load breakers would not be tripped.

   We agree. This is documented in Assumptions 18, 20 and 21.

7. The licensee assumed that a 480 Vac island-bus fault will trip the 480 Vac main bus breaker that is feeding the island bus.

   We agree. This is documented in Assumption 11.

8. The licensee stated that operator actions to minimize loads would be ineffective for the dc bus in the same room as the postulated fire. NOTE: FCS vital batteries will last 2.6 hours without minimizing dc loads. The first step will increase battery life to 4 hours. The second step will increase battery life to 8 hours.

   We agree with the licensee's assumption, as documented in Assumption 38. However, the analyst also assumes that, the Halon in the opposite train switchgear room would make load minimization ineffective for the opposite train dc bus.

   The NRC inspectors walked down the dc load minimization procedure. The major loads were required to be stripped within 15 minutes; however, most of these breakers are inside the fire area and/or an area filled with Halon. The inspectors noted that, during the actual fire, plant personnel (other than fire brigade) did not enter these rooms for over 2-1/2 hours. Therefore, the analyst did not give credit for minimizing dc loads, and assumed that the vital batteries would deplete in 2.6 hours.

   During a January 12, 2012 phone call with the licensee's PRA group, the licensee stated that they gave credit for minimization of dc loads on the opposite train on all single fire scenarios and gave credit for minimizing

loads for all two fire scenarios if the second fire was more than 2 hours after the first.

We disagreed with this approach. It is not clear that the operators would minimize dc loads on the dc train that was unaffected by the fire because that train would continue to be supplied by a battery charger. Additionally, after the first fire was extinguished, there is a strong possibility that nonvital loads would be reapplied to the unaffected train. These loads included plant lighting and turbine-generator auxiliaries.

9. The license made the following assumptions regarding recovery:

   a. Local reset of tripped breakers only applies to the twelve 480 Vac supply breakers upon breaker trip due to fault.

      We agree. No penalty was modeled for other breakers.

   b. Re-energization of manually de-energized 4160 Vac bus and associated 4160 and/or 480 Vac loads can be performed from the main control room.

      We agree. The nonrecovery values for the 4160 Vac buses reflect the better ability to re-energize these buses. Additionally, no penalty was modeled for the failure to energize any bus loads, once the primary bus was energized.

   c. Energizing a 480 Vac bus from the opposite side through the island bus can be done from the main control room.

      We agree. However, most core damage scenarios include a failure of the opposite train of power. Therefore, energizing a bus from the opposite side would likely be reflected in a success sequence.

   d. Bus 1B3C can be energized via 13.8 kV Transformer T1B-3C-1.

      The analyst walked down the procedure for energizing Bus 1B3C via 13.8 kV Transformer T1B-3C-1. The analyst noted that most of the steps in the procedure required access to the East Switchgear room and one step required opening a fire barrier door between the East and West Switchgear rooms. Following a postulated fire, one room would be filled with smoke while the other was filled with Halon. Therefore, the analyst determined that this procedure could not be performed before battery depletion.

      Additionally, the analyst noted that postulated fires in Buses 1B3C, 1B3C-4C, and 1B4C would prevent the performance of this procedure at any time following the fire and that the 13.8 kV supply would not survive seismic event.

      During a January 12, 2012 phone call with the licensee's PRA group, the licensee stated that their dependency review indicated that this

recovery was likely to be superseded by the recovery discussed under Item e. Therefore, they chose not to credit this recovery.

e. Steam Generator level indication will be available via the Distributed Control System following battery depletion.

   The analyst observed a simulator run that resulted in a station blackout with battery depletion. The operators noted that the steam generator level indication, powered by the 13.8 kV system did not appear to provide valid level indication. The licensee has not responded yet on this issue. However, the analyst determined that the availability of this indication was not relevant, given the credit provided for the use of portable steam generator level indication following battery depletion discussed under Section f.

f. Use of portable steam generator level indication is available.

   We agree. The analyst walked down the procedure for determining steam generator level following battery depletion. While the communications aspects were somewhat awkward, the analyst determined that the procedure was sound and could provide adequate level indication.

   The availability of level indication was a necessary condition for the recovery documented under "Adjustments to SPAR."

10. The licensee stated that they did not believe that the breaker/cradle assemblies would fail during a seismic event.

    We disagree. The inspectors noted that the root-cause analysis for the June, 2011 event stated that the fire resulted from insufficient cradle connections to the silver plated areas of the copper bus bar stabs, and the presence of hardened grease resulting in high-resistance connections. The licensee provided an analysis indicating that the breaker/cradle assembly was seismically qualified. However, the original evaluation and testing was performed with properly plated stabs and proper cradle connections to the bus bars. This evaluation was not clearly applicable to the condition of the cradles following the performance deficiency.

    Additionally, the vendors disagreed with the conclusions in the licensee's root-cause. The vendors concluded that the fire likely started in the bus compartment area, which contained bolted connections and welded bus bars, and not the breaker compartment. The bus compartment area had not been opened, inspected, or cleaned in at least 30 years. Bolted connections, hardened grease, and housekeeping issues are all items that make a switchgear more susceptible to seismic events.

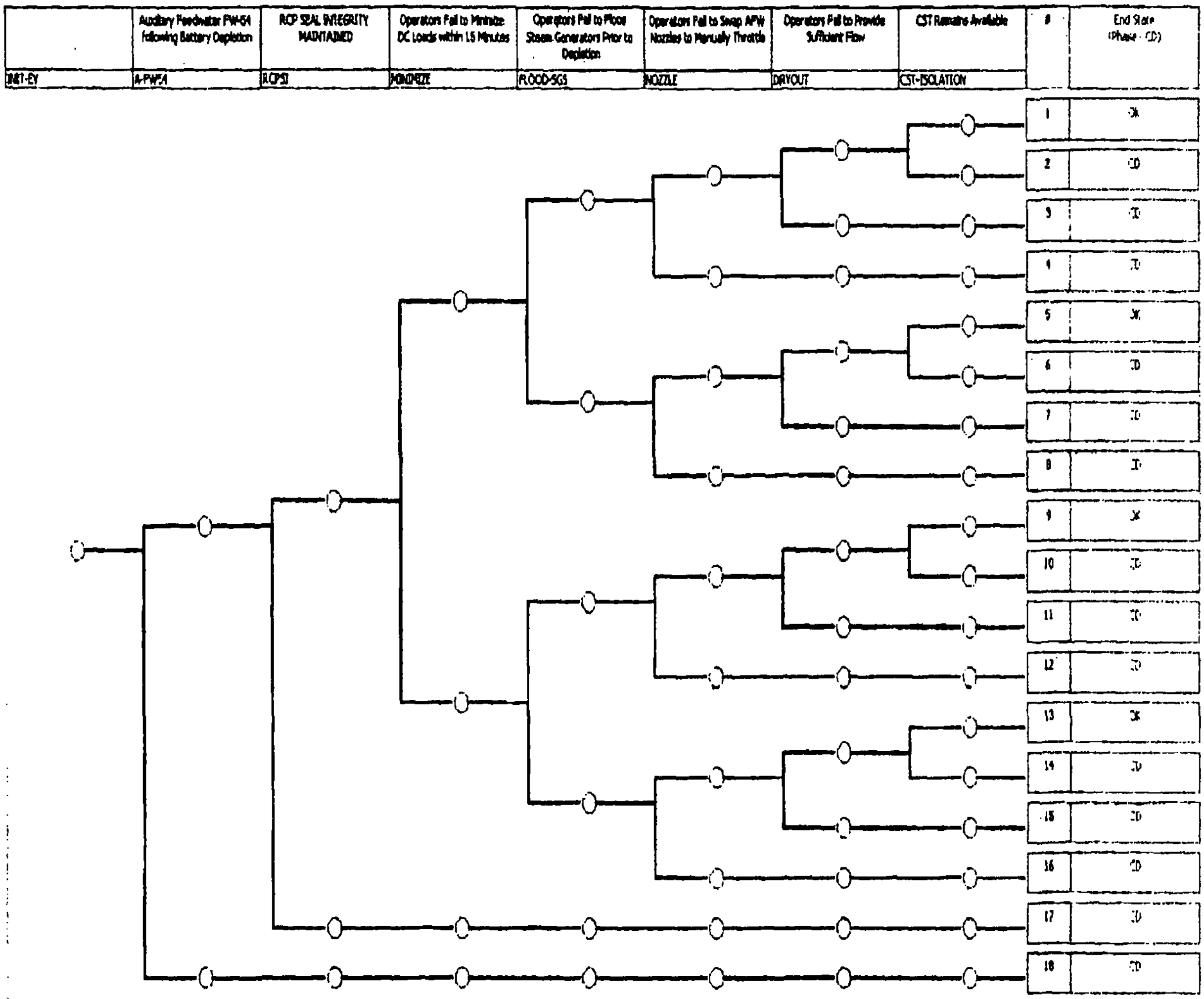
    During a January 12, 2012 phone call with the licensee's PRA group, we agreed to disagree on this issue.

11. On a phone call, licensee PRA group representatives stated that one reason their Assumption 9.e was important was that the availability of steam generator level indication allowed them to take credit for Turbine-Driven Auxiliary Feedwater Pump 10 continuing to run after vital battery depletion.

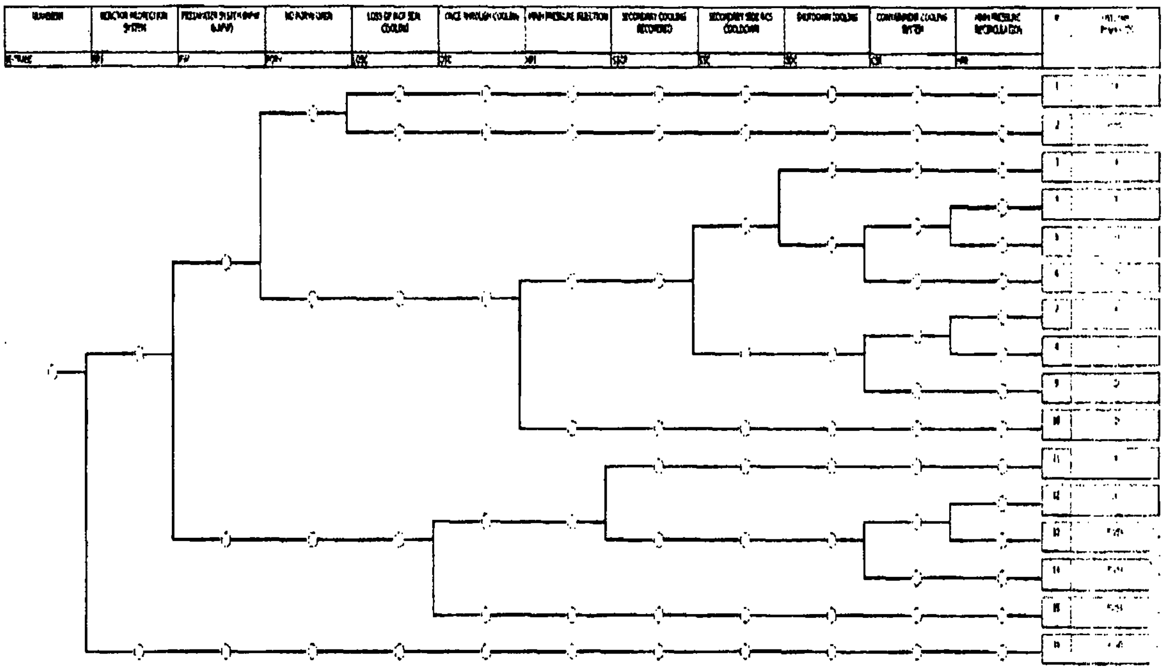
    The NRC analyst stated that the SPAR rules which apply to the significance determination process assume that plants go to core damage following vital battery depletion. As discussed under "Adjustments to the SPAR," credit was given to Diesel-Driven Auxiliary Feedwater Pump 54 after vital battery depletion because of the unique configuration of that pump at Fort Calhoun. However, the analyst noted the following reasons for not crediting Turbine-Driven Auxiliary Feedwater Pump 10 under similar conditions:

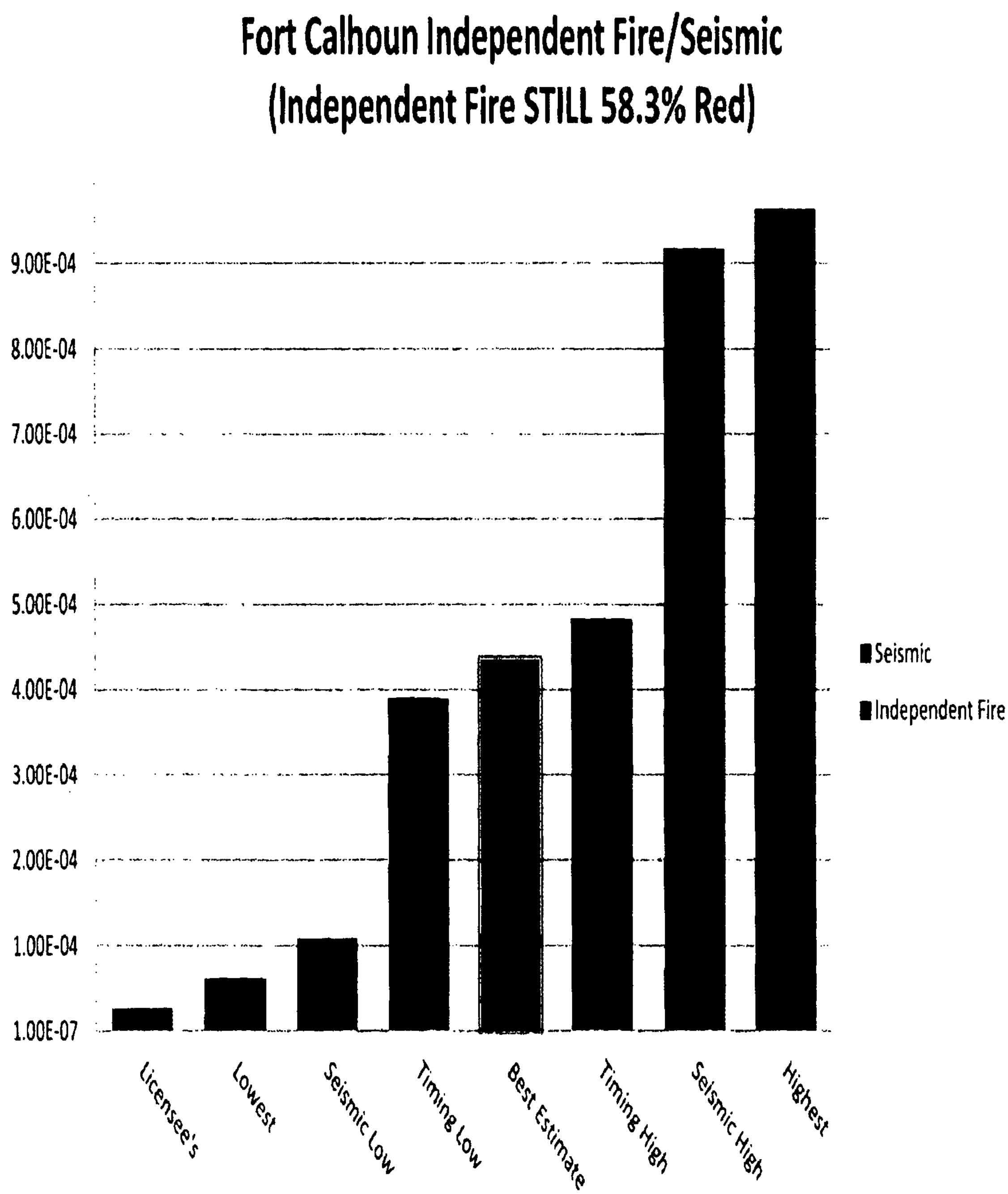
    1. There is a lot of dependence between using the turbine-driven auxiliary feedwater pump and the diesel-driven pump for use in station blackout following battery depletion
    2. Given credit for the turbine-driven auxiliary feedwater pump would be in conflict with the SPAR rules. Neither the NRC nor INL gives credit for turbine-driven pumps after battery depletion in the significance determination process. As such, all plant SPAR models indicate that the reactor will proceed to core damage upon vital battery depletion. Here is a listing of some of the documented reasons for this rule:

        a. No room cooling would be available
        b. No cooling would be available to the seal condenser
        c. No pressure indication would be available
        d. Difficulty relaying level indication to operators of pump controls
        e. Controls are in high temperature/low light area
        f. Flow path difficult to control with air-operated valves
        g. No capability of "black" operation for venting containment
        h. Fort Calhoun has small emergency feedwater tank

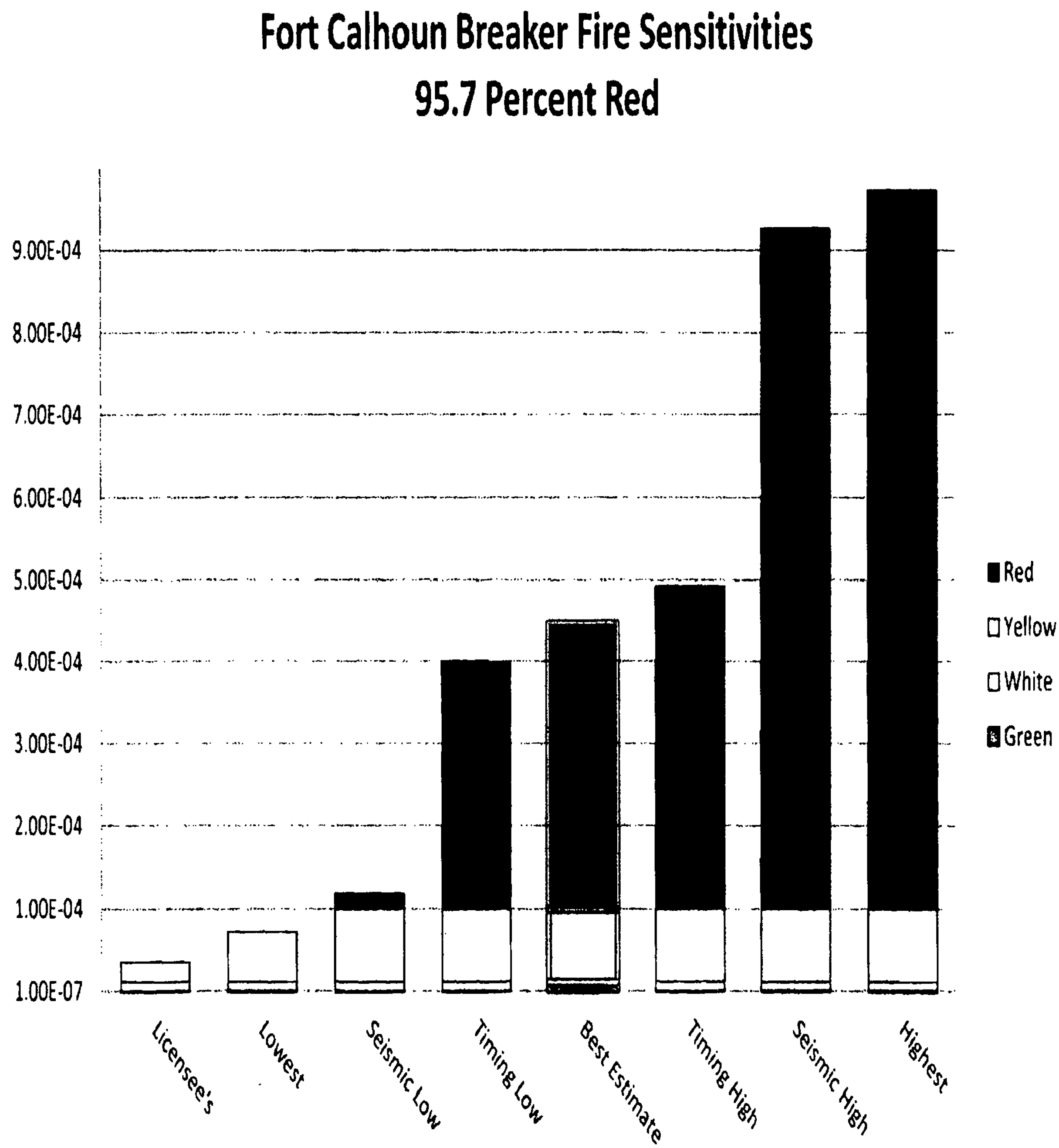


FW54 FW54 Cooling Following Battery Depletion Page 1 of 1

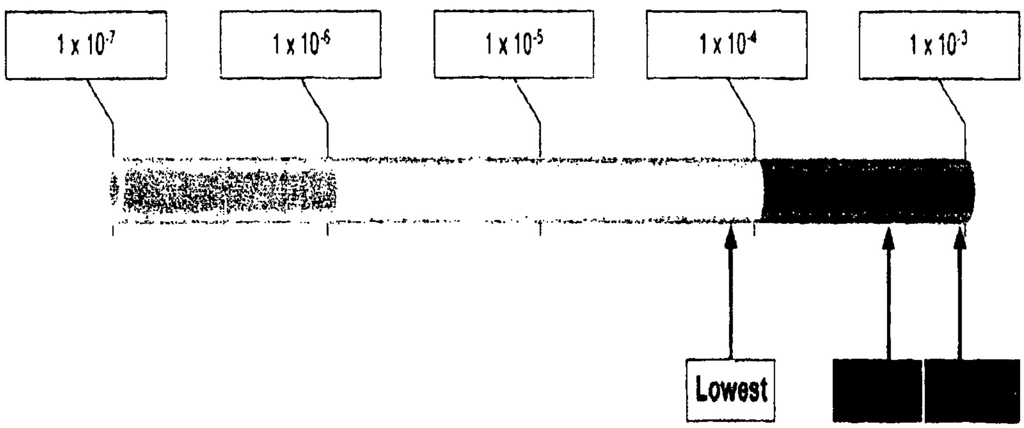




Fort Calhoun Independent Fire/Seismic
(Independent Fire STILL 58.3% Red)
9.00E-04
8.00E-04
7.00E-04
6.00E-04
5.00E-04
4.00E-04
3.00E-04
2.00E-04
1.00E-04
1.00E-07
Licensee's
Lowest
Seismic Low
Timing Low
Best Estimate
Timing High
Seismic High
Highest
Seismic
Independent Fire


Fort Calhoun Breaker Fire Sensitivities
95.7 Percent Red
9.00E-04
8.00E-04
7.00E-04
6.00E-04
5.00E-04
4.00E-04
3.00E-04
2.00E-04
1.00E-04
1.00E-07
Licensee's
Lowest
Seismic Low
Timing Low
Best Estimate
Timing High
Seismic High
Highest
Red
Yellow
White
Green

Fort Calhoun Breaker Fire Risk "Egg"



(one out of scope marking)

From:	Kellar, Ray
To:	Cain, Chuck; Carrington, Kenya; Collins, Elmo; Fuller, Karla; Gaines, Anthony; Herrera, Marisa; Howell, Art; OE Distribution; OEMAIL Resource; Quayle, Lisa; R4DIVDIR; R4DNMS-BC; R4DRP-BC; R4DRP-PE; R4DRP-RES; R4DRP-SRI; R4DRS-BC; R4DRS-SRA; R4DRS-TSB; R4OI; Burgess, Michele; White, Duane; Arrighi, Russell; Cai, June; Campbell, Andy; Crutchley, Mary Glenn; Faria-Ocasio, Carolyn; Ghasemian, Shahram; Hasan, Nasreen; Hernandez, Pete; Jarriel, Lisamarie; Rossi, Roberta; Solorio, Dave; Vito, David; Zimmerman, Roy; Mattern, Kevin; Morey, Dennis; Jimenez, Jose; Pascarelli, Robert; Peralta, Juan; Ashley, MaryAnn; Bowen, Jeremy; Robles, Jesse; Vaughn, Stephen; Coker, Shyrl; Furst, David; Gibson, Raymond; Riffle, Deani; Sturz, Fritz; Wastler, Sandra; Westreich, Barry; Barkman Marsh, Molly; Clark, Michael; Remsburg, Kristy; Safford, Carrie; Scott, Catherine; DeFrancisco, Anne; Holody, Daniel; McLaughlin, Marjorie; ODaniell, Cynthia; Checkle, Melanie; Evans, Carolyn; Slack, Linda; Sparks, Scott; Heck, Jared; Lougheed, Patricia; Olteanu, Carmen; Orth, Steven; Pelke, Paul; Tomczak, Tammy; Berger, Lynn; Dricks, Victor; Gepford, Heather; Kellar, Ray; Maier, Christi; Tannenbaum, Anita; Taylor, Nick; Uselding, Lara; Weaver, Judith
Cc:	Graves, Samuel; Miller, Geoffrey
Subject:	*** OUO PREDECISIONAL ENFORCEMENT INFORMATION*** RIV Enforcement Panel, Thursday, February 23, 2012***ONE REACTOR CASE
Date:	Tuesday, February 21, 2012 7:19:52 AM
Attachments:	SERP Worksheet EA-12-023 FCS Fire 2-17.docx SERP Worksheet Attachment EA-12-023 FCS Fire.docx

~~**OFFICIAL USE ONLY - PREDECISIONAL ENFORCEMENT INFORMATION****~~**
~~NOT FOR PUBLIC RELEASE~~
~~WITHOUT APPROVAL OF THE DIRECTOR, OE~~

REGION IV ENFORCEMENT PANEL & SERP AGENDA
Thursday, February 23, 2012

Region IV – VTC – Room 4085
Bridge No. 817-200-1912 – Access Code (b)(6)

Case 1 – 12:30 Central/1:30 Eastern

Fort Calhoun: – EA-12-023
Preliminary RED finding on Design Control, Corrective Actions and FP License Condition violations.

out of scope

Outside of Scope

******OFFICIAL USE ONLY - PREDECISIONAL ENFORCEMENT INFORMATION******

Ray L. Kellar, P.E.
Senior Enforcement Specialist

D5

817-200-1121 work
817-200-1122 fax
Ray.Kellar@nrc.gov

SERP Worksheet for SDP-Related Findings

EA-2012-023

SERP Date: February 23, 2012

Cornerstone Affected and Proposed Preliminary Results: Initiating Events – Preliminary Red

Licensee: Omaha Public Power District
Facility/Location: Fort Calhoun Station (FCS)
Docket No(s): 50-285
License No: DPR-40
Inspection Report No: 05000285/2011014
Date of Exit Meeting: TBD
Issue Sponsor: Region IV/Division of Reactor Safety

<u>Meeting Members</u>

Issue Sponsor:	Tony Vegel, Director, RIV /DRS
Technical Spokesperson(s):	Sam Graves, SRI, RIV/DRS/EB2
	Geoff Miller, BC, RIV/DRS/EB2
Program Spokesperson:	TBD
RIV Enforcement Specialist:	Ray Kellar (C Maier backup RIV ES)
OE Representative:	Gerry Gulla, SES, OE/EB

A. Brief Description of Issue

Inadequate maintenance and inadequate modification contributed to a catastrophic switchgear fire that started in a safety-related 480 Vac feeder breaker. The fire was created by one or more high-resistance connections within the switchgear. The high-resistance connections occurred as a result of improper installation of new circuit breakers and inadequate switchgear maintenance. Smoke and soot from the fire migrated to a bus cross-tie, causing an additional electrical fault that adversely affected the redundant train. The electrical separation scheme failed to function as designed, and between the actual electrical system response and the operator response per procedures, six of the nine 480 Vac safety-related load center buses were de-energized. When the event occurred the plant was in cold shutdown for a planned refueling outage, however, the breakers could have failed at any time from their installation until the failure occurred, a time frame of approximately 19 months.

In 2008 the licensee identified a significant condition adverse to quality involving, in part, inadequate cleaning of hardened grease from electrical contacts and inadequate maintenance practices for 480 Vac bus-tie breakers. In 2009 the NRC concluded that the licensee was performing inadequate maintenance on their safety-related breakers and switchgear and subsequently issued a non-cited violation. The licensee had not changed their maintenance practices to address the deficiencies since the violation was issued in early 2010. This inspection identified concerns with failure to clean hardened grease from bus work and connections, work instructions that allowed workers to skip most of the bus work because it could be considered difficult to access, failure to torque bus connections and/or failure to document torquing them, and not specifying the appropriate torque values. Each of these concerns, along with images of the damage, results of reports from forensics experts and vendors, and the history of inadequate maintenance led the NRC to conclude that the lack of adequate maintenance had an equal likelihood of contributing to the fire as

D6

the modification problems. Due to the catastrophic nature of the damage, the exact cause cannot be determined.

The event showed unexpected electrical system interactions. Combustion products from the fire in load center 1B4A migrated across normally open bus-tie breaker BT-1B4A into the non-segregated bus duct, shorting all three electrical phases. The non-segregated bus ducting electrically connected load center 1B4A with the Island Bus 1B3A-4A and, through normally closed bus-tie breaker BT-1B3A, to the redundant safe shutdown train. This resulted in de-energizing both the redundant train Bus 1B3A and the Island Bus 1B3A-4A. The fire in load center 1B4A exposed vulnerabilities in FCS implementation of electrical separation. Also, the fire in 1B4A caused grounded circuits on both trains of the Class 1E 125 Vdc distribution system. The apparent lack of separation for the 480 Vac system is still being evaluated by the licensee.

The inspection also noted that during the 3 days prior to the fire, the licensee failed to adequately investigate the source of an acrid odor that was reported in the switchgear room, and therefore failed to prevent the resulting catastrophic electrical fault and fire.

B. Statement of the Performance Deficiency

The failure to ensure that the 480 Vac electrical power distribution system design requirements were properly implemented and maintained through proper maintenance, modification, and design activities contributed to the conditions that allowed a catastrophic fire in a switchgear, which impacted the required safe shutdown capability of the plant. This was a performance deficiency. Specifically: (1) design reviews and work planning for a modification, to install twelve new 480 Vac load center breakers, failed to ensure that the cradle adapter assemblies had a low-resistance connection with the switchgear bus bars by establishing a proper fit and requiring low resistance measurements; (2) preventive maintenance activities were inadequate to ensure proper cleaning of conductors, proper torquing of bolted conductor and bus bar connections, or adequate inspection for abnormal connection temperatures; and (3) design reviews of the electrical protection and train separation of the 480 Vac electrical power distribution system were inadequate to ensure that a fire in load center 1B4A would not adversely impact operation of redundant safe shutdown equipment in load center 1B3A, as required by the fire protection program.

C. Significance Determination Basis

1. Reactor Inspection for IE, MS, BI cornerstones

a. Phase 1 screening logic, results and assumptions

In accordance with NRC Inspection Manual Chapter (IMC) 0612, Appendix B, "Issue Screening," this finding was determined to be more than minor because it was associated with both the protection against external events attribute (i.e., fire) and the design control attribute of the Initiating Events cornerstone. The finding affected the Initiating Events cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the performance deficiency elements each contributed to making it more likely that Fort Calhoun Station could have a significant fire in the safety-related bus work that would upset plant stability and challenge critical safety functions. Mitigating

systems were actually affected during the event and Barrier Integrity (spent fuel pool cooling) was impacted, but the inspectors determined that the Initiating Events cornerstone was the most appropriate cornerstone for this finding because it best reflects the dominant risk associated with the finding.

The finding was best characterized as a transient initiator in Table 4a, and was determined to contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. Therefore, Table 4a directs the user to Appendix A for further analysis.

b. Phase 2 Risk Evaluation

Appendix A to IMC 0609 directs that a Phase 3 analysis be performed if the Phase 2 SDP pre-solved tables/worksheets do not clearly address the inspection finding. A phase 3 analysis was performed for this finding because the finding involved external event initiators (fire), and the pre-solved tables do not clearly address the finding.

c. Phase 3 Analysis

The senior reactor analyst completed a Phase 3 analysis using the plant-specific Standardized Plant Analysis Risk Model for Fort Calhoun, Revision 8.15, the licensee's Individual Plant Examination of External Events, and hand calculations. The exposure period of 1 year represented the maximum exposure time allowable in the significance determination process. The analyst estimated the initiating event likelihood for a single fire of 7.0×10^{-2}/year. The analysis covered the risk affected by the performance deficiency for postulated fires of any of the nine normally closed breakers including the potential for one additional common cause fire initiator. The resulting change in core damage frequency (ΔCDF) was 1.1×10^{-4}. Additionally, seismically-induced fires were postulated based on the characteristics of the performance deficiency. The quantified ΔCDF for seismically-induced fires was 3.3×10^{-4}. Finally, the analyst determined that the finding did not involve a significant increase in the risk of a large, early release of radiation. The final result was calculated to be 4×10^{-4} indicating that the finding was of high safety significance (Red). Additional qualitative considerations suggest that the actual risk may be higher than this calculated value.

A detailed preliminary significance determination summary is attached.

2. All Other Inspection Findings

None.

D. Proposed Enforcement.

Region IV intends to issue a choice letter with Inspection Report 05000285/2011014 for the performance deficiency described above with three associated violations, preliminarily determined to be of high safety significance (Red). The violations are described below.

a. Regulatory requirement not met.

- 10 CFR Part 50, Appendix B, Criterion III, "Design Control."
- 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action."
- License Condition 3.D, "Fire Protection Program."

b. Proposed citation.

Three self-revealing violations were associated with this performance deficiency:

- A violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure to ensure that design changes were subject to design control measures commensurate with those applied to the original design; and, that measures were established to assure that applicable regulatory requirements and the design basis, for those safety-related structures, systems, and components were correctly translated into specifications, drawings, procedures, and instructions;

- A violation of 10 CFR Part 50, Appendix B, Criterion XVI "Corrective Action," for the failure to establish measures to assure that the cause of a significant condition adverse to quality was determined and corrective action taken to preclude repetition;

- A violation of License Condition 3.D, "Fire Protection Program," for the failure to ensure that the electrical protection and physical design of the 480 Vac electrical power distribution system provided the electrical bus separation required by the fire protection program.

Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part that: (1) design changes, including field changes, be subject to design control measures commensurate with those applied to the original design; (2) measures be established to assure that applicable regulatory requirements and the design basis for those safety-related structures, systems and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions; and (3) these measures shall include provisions to assure that appropriate quality standards are specified and included in design documents and that deviations from such standards are controlled.

Contrary to the above requirement, from November 2009 to June 7, 2011, the licensee failed to ensure that design changes were subject to design control measures commensurate with those applied to the original design; failed to assure that applicable regulatory requirements and the design basis for those safety-related structures, systems, and components to which this appendix applies were correctly translated into drawings, procedures, and instructions; and failed to ensure that these measures include provisions to assure that appropriate quality standards were specified and included in the design documents. Specifically, design reviews, work planning and instructions for a modification to install new 480 Vac load center breakers failed to ensure that the cradle adapter assemblies had low resistance connections with the switchgear bus bars by establishing a proper fit and requiring

low resistance measurements to assure that design basis requirements were maintained.

Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part that measures be established to assure that conditions adverse to quality such as failures, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.

Contrary to the above requirement, from May 22, 2008, to June 7, 2011, the licensee failed to assure that the case of the significant condition adverse to quality was determined and take corrective actions to preclude repetition. Specifically, the licensee failed to ensure that their preventative maintenance program for the safety-related 480 Vac electrical power distribution system was adequate to ensure proper cleaning of conductors, proper torquing of bolted conductor or bus bar connections, and adequate inspection for abnormal connection temperatures. In 2008, the licensee identified that preventative maintenance procedure EM-PM-EX-1200, "Inspection and Maintenance of Model AKD-5 Low Voltage Switchgear," was less than adequate as a result of a root cause analysis for the failure of bus-tie breaker BT-1B3A to close on demand and loss of bus 1B3A. The licensee categorized this failure as a significant condition adverse to quality. The analysis concluded, in part, that breaker BT-1B3A had high resistance connections, which occurred as a result of both procedure deficiencies and inadequate implementation, resulting in the failure to remove dirt and hardened grease from electrical contacts. The licensee implemented corrective actions to address these procedural deficiencies; however, the corrective actions were inadequate to prevent high resistance connections in load center 1B4A due to the presence of hardened grease and oxidation.

License Condition 3.D, "Fire Protection Program," requires, in part, that the licensee implement and maintain in effect all provisions of the approved Fire Protection Program as described in the Updated Safety Analysis Report (USAR) and as approved in NRC safety evaluation reports. Section 9.11.1 of the USAR describes the fire protection system design basis and states, in part, that the design basis of the fire protection systems includes commitments to 10 CFR 50, Appendix R, Sections III.G, III.J, and III.O. Section III.G, "Fire protection of safe shutdown capability," requires, in part, that fire protection features be provided for structures, systems, and components important to safe shutdown, and that these features be capable of limiting fire damage so that one train of systems necessary to achieve and maintain hot shutdown conditions is free of fire damage.

Contrary to the above requirement, from November 2009, to June 7, 2011, the licensee failed to implement and maintain in effect all provisions of the approved Fire Protection Program. Specifically, the licensee failed to ensure that design reviews for electrical protection and train separation of the 480 Vac electrical power distribution system were adequate to ensure that a fire in load center 1B4A would not adversely affect operation of redundant safe shutdown equipment in load center 1B3A, such that one train of systems necessary to achieve and maintain hot shutdown conditions were free of fire damage as required by the fire protection program. Combustion products from the fire in load center 1B4A migrated across normally open bus-tie breaker BT-1B4A into the non-segregated bus duct, shorting

all three electrical phases. The non-segregated bus ducting electrically connected load center 1B4A with the Island Bus 1B3A-4A and, through normally closed bus-tie breaker BT-1B3A, to the redundant safe shutdown train.

c. Historical precedent.

None.

E. Determination of Follow-up Review (as needed)

Per IMC 0609, NRR, and OE will review and concur with the final significance for all Red or Yellow findings.

PRELIMINARY PHASE 3 SIGNIFICANCE DETERMINATION
IMPROPER MODIFICATION/MAINTENANCE OF VITAL 480 VAC SWITCHGEAR

Analyst Assumptions

1. The Standardized Plant Analysis Risk Model for Fort Calhoun (SPAR), Revision 8.15, as modified by the analyst to include additional 480 Vac island buses and nonrecovery basic events for failure of 480 Vac load centers, was the best tool for quantifying the risk of the subject performance deficiency.

2. The SPAR, Revision 8.15 was modified to include 480 Vac Island Buses 1B3B-4B and 1B3C-4C including the appropriate mapping of safety functions supported by these buses.

3. The analyst assumed that, for this evaluation, basic events involving breaker failures for the nine 480 Vac normally-closed supply breakers plus the two 4160 Vac supply breakers and/or bus failures could be appropriately divided into a revised nominal failure rate and a nonrecovery whose product is equal to the original nominal failure rate as provided in Table 1.

Table 1
Revised/Additional Baseline Basic Events

Basic Event	Original	Revised	Nonrecovery BE	Value
ACP-CRB-CO-1B3A	3.6E-06	1.2E-05	ACP-BAC-1B3A-REC	3.0E-01
ACP-CRB-CO-1B3B	3.6E-06	1.2E-05	ACP-BAC-1B3B-REC	3.0E-01
ACP-CRB-CO-1B3C	3.6E-06	1.2E-05	ACP-BAC-1B3C-REC	3.0E-01
ACP-CRB-CO-1B4A	3.6E-06	1.2E-05	ACP-BAC-1B4A-REC	3.0E-01
ACP-CRB-CO-1B4B	3.6E-06	1.2E-05	ACP-BAC-1B4B-REC	3.0E-01
ACP-CRB-CO-1B4C	3.6E-06	1.2E-05	ACP-BAC-1B4C-REC	3.0E-01
ACP-CRB-CO-BT1B3A	3.6E-06	1.2E-05	ACP-BAC-1B3A4A-REC	3.0E-01
ACP-CRB-CO-BT1B3B	3.6E-06	1.2E-05	ACP-BAC-1B3B4B-REC	3.0E-01
ACP-CRB-CO-1BT1B3C	3.6E-06	1.2E-05	ACP-BAC-1B3C4C-REC	3.0E-01
ACP-BAC-LP-1A3	9.6E-06	2.2E-04	DIV-A-AC-REC	4.3E-02
ACP-BAC-LP-1A4	9.6E-06	2.2E-04	DIV-B-AC-REC	4.3E-02

4. The twelve subject breaker cubicles were modified in November 2009 and were in service from that point until the fire in June 2011.

5. Given that the reactor was in operation from November 2009 through April 2011, this finding is being evaluated as an at-power event because the failure was more likely to have occurred during power operations than at shutdown, and the failure mode was determined to be independent of plant or system operational mode.

6. Using best-available information, the inspectors concluded that the fire was caused by high-resistance connections between the cradle assembly and switchgear bus bars which resulted in overheating of the connections under

load. The deficient connections were a result of inadequate maintenance and/or modification.

7. Nine of the twelve 480 Vac supply breakers were closed for most of the time from November 2009 to June 2011.

8. The analyst evaluated the time frame over which the finding was reasonably known to have existed. The analyst determined that the breaker cubicles could have failed at any time from their installation in November 2009 until the failure in June, 2011, which was approximately 19 months.

9. In accordance with Manual Chapter 0609, Appendix A, Attachment 2, "Site Specific Risk-Informed Inspection Notebook Usage Rules," Rule 1.1, "Exposure Time," the analyst determined that the maximum exposure time used in the SDP should be used, which is limited to 1 year.

10. The inspectors noted that the Fire in Bus 1B4A caused the failure of Island Bus 1B3A-4A despite Breaker BT-1B4A being open. Therefore, the analyst assumed that any postulated fire in a 480 Vac load center with a normally-open tie breaker would cause the failure of its associated island bus.

11. The inspectors noted that all three island buses were physically located inside the switchgear containing the load center with the normally-closed tie breaker. One example is that Bus 1B3A is located in the same physical switchgear as Bus 1B3A-4A. Therefore, a hot gas layer would be free to communicate between cubicles in these switchgear. Therefore, analyst determined that any postulated fire in a 480 Vac load center with a normally-closed tie breaker would cause the failure of its associated island bus. Likewise, any postulated fire in a normally-closed tie breaker cradle would cause the failure of the associated load center.

12. During this time frame, a postulated failure of the breaker and/or cradle for these nine normally closed breakers would result in a fire that would cause severe damage to the bus, making the associated 480 Vac buses listed in Table 2 unrecoverable.

Table 2 Unrecoverable Bus Failures From Postulated Fires		
Fire Location	Buses Failed	
Breaker Cradle 1B3A	1B3A	1B3A-4A
Breaker Cradle 1B3B	1B3B	1B3B-4B
Breaker Cradle 1B3C	1B3C	1B3C-4C
Breaker Cradle 1B4A	1B4A	1B3A-4A
Breaker Cradle 1B4B	1B4B	1B3B-4B
Breaker Cradle 1B4C	1B4C	1B3C-4C
Breaker Cradle BT-1B3A	1B3A	1B3A-4A
Breaker Cradle BT-1B4B	1B4B	1B3B-4B
Breaker Cradle BT-1B3C	1B3C	1B3C-4C

13. The analyst determined that those buses documented under Assumption 12 as unrecoverable were not available for operation at any time during the mission times covered by the subject evaluation.

14. By plant procedures, both 480 Vac and 4160 Vac buses are de-energized in an effort to isolate electric power to the affected bus. Table 3 indicates the additional buses that would be de-energized by operators following a postulated fire.

Table 3 Buses De-energized Following Postulated Fires					
Fire Location	Buses De-energized				
Breaker Cradle 1B3A	1B3B	1B3C	1A3	1B3C-4C	
Breaker Cradle 1B3B	1B3A	1B3C	1A3	1B3C-4C	1B3A-4A
Breaker Cradle 1B3C	1B3A	1B3B	1A3	1B3A-4A	
Breaker Cradle 1B4A	1B4B	1B4C	1A4	1B3B-4B	
Breaker Cradle 1B4B	1B4A	1B4C	1A4		
Breaker Cradle 1B4C	1B4A	1B4B	1A4	1B3B-4B	
Breaker Cradle BT-1B3A	1B3B	1B3C	1A3	1B3C-4C	
Breaker Cradle BT-1B4B	1B4A	1B4C	1A4		
Breaker Cradle BT-1B3C	1B3A	1B3B	1A3	1B3A-4A	

15. Given the plant design of the normally open bus-tie breakers and the associated buswork, the smoke from a postulated fire in a 480 Vac load center with a normally-open bus-tie breaker will cause a fault in the nonsegregated bus resulting in the de-energization of the associated cross-train bus. Table 4 documents these additional buses that would be de-energized.

Table 4 Buses De-energized by Fire Faults From Postulated Fires	
Fire Location	Buses Failed
Breaker Cradle 1B3B	1B4B
Breaker Cradle 1B4A	1B3A
Breaker Cradle 1B4C	1B3C

16. The analyst assumed that the buses de-energized as documented under Assumptions 14 and 15 had the potential to be recovered prior to core damage, given appropriate operator action.

17. The breaker failure probability can be calculated by multiplying 1 failure of 9 breaker cradles that are normally subject to electrical load and dividing by the 19 months that they were in service.

18. In accordance with Abnormal Operating Procedure, AOP-06, "Fire Emergency," Revision 25, a fire in a vital 480 Vac load center requires operators to initially de-energize the associated 4160 Vac switchgear, opening all of the normally-closed breakers on that side of the ac power system.

19. The baseline core damage frequency was determined to be based on the frequency of an energetic fault in the most limiting fire scenario. The generic fire for vital switchgear from NRC Inspection Manual Chapter 0609, Appendix F, Attachment 4 is 4.70×10^{-6}/year. The smaller switchgear at Fort Calhoun Station have 5 vertical sections, resulting in an initiating event frequency of 2.4×10^{-5}/year. Therefore, as an example, the baseline risk for the postulated failure of Switchgear 1B4A, with a conditional core damage probability of 6.4×10^{-5}, will be 1.5×10^{-9}/year.

20. Following any of the fires postulated in Assumption 12 a reactor transient would occur, either directly from instrumentation and/or lost equipment or via licensed operators following plant procedures or required Technical Specifications.

21. Abnormal Operating Procedure, AOP-06, "Fire Emergency," Revision 25, directs operators to close and de-energize pressurizer power-operated relief valves and their associated block valves prior to de-energizing vital buses during a fire. As such, the analyst assumed that the pressurizer power-operated relief valves would not be available throughout the postulated event.

22. Technical Specification 2.7(2)f. permits one of the buses connected to Bus 1A3 or 1A4 to be inoperable for up to 8 hours. Technical Specification 2.7(2), "Modification of Minimum Requirements," requires that with Paragraph f not met:

". . . the reactor shall be placed in hot shutdown within the following 12 hours. If the violation is not corrected within an additional 12 hours, the reactor shall be placed in a cold shutdown condition within an additional 24 hours."

The analyst noted that licensed operators may decide to cool down the reactor more rapidly than required by Technical Specifications. However, many of the scenarios would require multiple manual system alignments to achieve cold shutdown presenting a potential that reactor cooldown timing would be limited more by manpower available than by license restrictions. Therefore, the analyst assumed that the reactor would be in a condition above cold shutdown for 56 hours following a postulated bus fire.

23. In lieu of a complex (while more traditional) common cause failure analysis, the analyst assumed that there was a potential for a second fire to initiate during the Technical Specification Allowed Outage Time and evaluated all potential two fire combinations. This was necessitated by both the frequency of a postulated fire and the consequences being too high to truncate.

24. The nonrecovery probability for restoration of buses that were manually de-energized during a postulated fire can be best quantified using the SPAR-H Method described in NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Method."

25. The operators, electricians and fire brigade personnel responding to the fire and the associated reactor event will be under high stress throughout the response. Therefore, all human reliability analysis would use high stress as a performance shaping factor in both the diagnosis and actions.

26. Given the need to ensure that the fire is extinguished and then to evacuate Halon and smoke products from the East and West Switchgear rooms following a postulated fire, the analyst reviewed the timing during the actual event. The space was not cleared, such that maintenance personnel could access the area, until almost 3 hours after the report of the fire. Therefore, the analyst determined that no recovery potential should be credited for core damage sequences lasting 2 hours or less.

27. Based on the need to ensure that all faults are properly isolated, the evolution of determining that a de-energized switchgear was capable of being energized again following a postulated fire was considered to be moderately complex. Therefore the diagnosis portion of this human reliability analysis should be increased.

28. Given the condition of Bus 1B4A following the fire, the analyst assumed that the smoke, soot coating of equipment, heat and lighting conditions in which operators and electricians would be locating, measuring and isolating all faults following any postulated fire in a 480 Vac bus would make these functions more difficult. Therefore, the ergonomics were considered to be poor for the diagnosis portion of the human reliability analysis.

29. The twelve 480 Vac supply breakers had a unique design requiring maintenance personnel to perform a local reset operation after a trip prior to reclosing the breaker. This delayed the operators in closing the breakers because of insufficient instructions to the operators, combined with a lack of familiarity with the design. Therefore, the analyst assumed that the procedures for the action portion of the human reliability analysis were poor.

30. A seismic event could result in the failure of the breaker/breaker cradle interface and/or bolted bus bars in a manner similar to the fire that occurred on June 7, 2011.

31. The failure discussed under Assumption 30 would occur with about the same fragility of the offsite power insulator stacks which represents the vibration levels that start to cause differential motion between uncoupled components.

32. Failures of more than two breaker cradles following a seismic event are possible. However, the evaluation of the risk for these scenarios would become prohibitive based on the large number of scenarios that would be possible and would not be expected to contribute significantly to the overall risk.

33. Once the plant is in cold shutdown, as required by Technical Specifications, the unavailability of two 480 Vac busses will continue to impact the risk of plant shutdown for several months while investigation and repairs are conducted.

34. The shutdown risk referred to under Assumption 33 is best evaluated in a qualitative manner for the subject significance determination.

35. The 480 Vac distribution system at Fort Calhoun Station supports the cooling of the spent fuel pool. As a result, the subject performance deficiency impacts the risk of core damage in the spent fuel pool. This risk is best evaluated in a qualitative manner for the subject significance determination.

36. While Assumption 8 describes a straight-line failure rate for the subject breaker cubicles, the actual failure frequency was most likely some form of an exponential curve. As such, the failure frequency would have been higher for the year of the exposure period than for the preceding 9 months. The additional risk associated with the higher failure rate is best evaluated in a qualitative manner for the subject significance determination.

37. For some fire scenarios, a fire in one bus will affect the dc control power for buses in the opposite train. As a result, manual operations of all breakers would be required for operator responses, increasing the risk associated with the finding. The additional risk resulting from the additional work load on operators responding to the postulated events is best evaluated in a qualitative manner for the subject significance determination.

38. Because during all postulated scenarios, one switchgear room would be inaccessible for 2-1/2 hours and the other would be filled with Halon making operator actions difficult and delayed, operators would not be able to strip

plant lighting loads within 15 minutes as required by plant procedures. The result would lead to vital battery depletion in approximately 2.6 hours.

Exposure Period

As stated in Assumptions 4, 7 and 8, the twelve subject breaker cubicles were modified in November 2009 and were in service from that point until the fire in June 2011. The analyst evaluated the time frame over which the finding was reasonably known to have existed. The analyst determined that the breaker cubicles could have failed at any time from their installation in November 2009 until the failure in June, 2011, which was approximately 19 months. The repair time for the failed buses continued as of December 2011.

As stated in Assumption 9, in accordance with Manual Chapter 0609, Appendix A, Attachment 2, "Site Specific Risk-Informed Inspection Notebook Usage Rules," Rule 1.1, "Exposure Time," the analyst determined that the maximum exposure time used in the SDP should be used, which is limited to 1 year.

<u>Fire-Induced Risk</u>

Fire Initiating Event Likelihood

As stated in Assumption 17, the breaker cubicle failure probability can be calculated by multiplying 1 failure of 9 breaker cradles and dividing by the 19 months that they were in service. Given that a breaker cubicle failure would result in catastrophic failure of the associated vital bus, the analyst calculated the initiating event likelihood (λ_{Fire}) as follows:

$$\begin{aligned}\lambda_{Fire} &= \text{failures} \div (\text{breakers} * \text{months})\\ &= 1 \div (9 \text{ breakers} * 19 \text{ months})\\ &= 5.9 \times 10^{-3} \text{ /month} * 12 \text{ months/year}\\ &= 7.0 \times 10^{-2} \text{ /year}\end{aligned}$$

Safety Impact

As stated in Assumption 12, any postulated fire in one of the nine normally-closed breakers would result in the long-term failure of two vital 480 Vac buses. The risk-important equipment supplied by these buses would not be available throughout the accident sequences modeled and subsequent repair. Additionally, as stated in Assumptions 14 and 15, any postulated fire in one of the nine normally-closed breakers would result in operators de-energizing multiple additional vital buses and the potential de-energization of one additional bus caused by fire-related faults. The risk-important equipment supplied by those buses would not be available until the fire was extinguished, smoke and Halon removed from the switchgear rooms, plant personnel were capable of

determining that the buses were safe to re-energize, and operators re-energized the buses and reconnected the risk-important loads.

Application of Recovery

As stated in Assumptions 13 and 16, the potential for recovery of vital buses was grouped into the following categories:

1. The analyst determined that those buses documented under Assumption 12 as unrecoverable were damaged and not available for operation at any time during the 24 hour mission time (56 hours for two fire scenarios) covered by the subject evaluation.

2. The nonrecovery probability for restoration of undamaged 480 Vac buses de-energized by operators during a postulated fire were quantified using the SPAR-H Method described in NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Method." This analysis is documented in Table 5.

3. The nonrecovery probability for restoration of undamaged 480 Vac buses de-energized by fire-induced faults during a postulated fire were quantified using the SPAR-H Method described in NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Method." This analysis is documented in Table 5.

4. The nonrecovery probability for restoration of 4160 Vac buses de-energized by operators during a postulated fire were quantified using the SPAR-H Method described in NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Method." This analysis is documented in Table 6.

Table 5 Recovering 480 Vac Electrical Buses De-energized during Fire				
Performance Shaping Factor	**Diagnosis**		**Action**	
	PSF Level	**Multiplier**	**PSF Level**	**Multiplier**
Time:	Nominal	1.0	Nominal	1.0
Stress:	High	2.0	High	2.0
Complexity:	Moderately Complex	2.0	Nominal	1.0
Experience:	Nominal	1.0	Nominal	1.0
Procedures:	Nominal	1.0	Available, but Poor	5.0
Ergonomics:	Poor	10.0	Nominal	1.0
Fitness for Duty:	Nominal	1.0	Nominal	1.0
Work Processes:	Nominal	1.0	Nominal	1.0
	Nominal	1.0E-02		1.0E-03
	Adjusted	4.0E-01		2.0E-02
	Odds Ratio	2.9E-01		9.9E-03
	Composite	40		10
Failure to Re-energize 480 Vac Bus Following Fire Probability:				3.0E-01

Table 6 Recovering 4160 Vac Electrical Buses De-energized during Fire				
Performance Shaping Factor	Diagnosis		Action	
	PSF Level	Multiplier	PSF Level	Multiplier
Time:	Nominal	1.0	Nominal	1.0
Stress:	High	2.0	High	2.0
Complexity:	Moderately Complex	2.0	Nominal	1.0
Experience:	Nominal	1.0	Nominal	1.0
Procedures:	Nominal	1.0	Nominal	1.0
Ergonomics:	Nominal	1.0	Nominal	1.0
Fitness for Duty:	Nominal	1.0	Nominal	1.0
Work Processes:	Nominal	1.0	Nominal	1.0
	Nominal	1.0E-02		1.0E-03
	Adjusted	4.0E-02		2.0E-03
	Odds Ratio	3.9E-02		2.0E-03
	Composite	4		2
Failure to Reenergize 4160 Vac Bus Following Fire Probability:				4.1E-02

Adjustments to SPAR

The analyst noted that the results of the initial SPAR evaluation were more significant than both the licensee's evaluation and the risk-informed notebook. In reviewing these differences, it was noted that the licensee's model provided for recovery of auxiliary feedwater during a station blackout, following battery depletion. The licensee stated that Fort Calhoun Station had a unique arrangement for auxiliary feedwater. Auxiliary Feedwater Pump FW-54 is diesel driven and does not rely on vital ac or dc power. The pump is supplied with fuel from Diesel Fuel Oil Storage System Tank FO-10. Tank FO-10 has a minimum volume of 10,000 gallons of diesel fuel as required by Technical Specification 2.7. Eight thousand gallons of the tank's inventory are readily available for use by Pump FW-54. Therefore, the pump could run for 24 hours without fuel addition. The analyst noted that the condensate storage tank would provide about 30 hours of water based on licensee calculated steam generator steaming rates. Therefore, makeup water sources were not assessed.

Traditionally, SPAR methodology assumes that auxiliary feedwater fails upon loss of vital batteries. This failure assumes that instrumentation is lost and operators overfill the steam generators. Once the steam generators fill to the main steam lines, water flowing into the steam lines suppresses the steam supply to the turbine-driven pump. Given the postulated failure of the turbine-driven pump, the steam generators boil dry and the scenario leads to core damage. Providing a reliable diesel-driven pump resolves this problem, and the pump could theoretically continue to feed the steam generators for the 24-hour mission time.

To give credit for Pump FW-54, the failure mechanisms of the system, including the operator actions required to continue to feed the steam generators for 24 hours were evaluated. These included the following:

- Pump FW-54 must continue to run for 24 hours, including fuel supply, suction source, and the operator attention necessary.

- Operators must transfer the discharge of the system to the auxiliary feedwater nozzles and manually throttle discharge Valves HCV-11078 and HCV-11088 prior to battery depletion.

- Operators must ensure that there is sufficient auxiliary feedwater flow to prevent core damage.

- The reactor coolant pump seals must remain intact for 24 hours without vital ac or dc power. The analyst determined that the reactor coolant pump seals at Fort Calhoun Station were of the upgraded seal design. Therefore, the analyst utilized the value for the probability of seal failure during an extended loss of power, documented in the SPAR model. This value was 8.9×10^{-3}.

- Operators must isolate the condensate storage tank prior to loss of pressure in the associated nitrogen bottle. This action requires manual isolation of the hotwell supply line before the air-operated valve fails open and the condensate storage tank inventory is vacuum dragged to the condenser.

- Operators have a varying amount of time to perform these actions, depending on the success or failure of two operator actions:

  (1) operators minimize dc loads on the battery quickly following a station blackout and;
  (2) operators flood the steam generators to 94 percent wide-range level prior to battery depletion using either Pump FW-54 or the turbine-driven auxiliary feedwater pump.

The analyst used generic steam generator data and certain plant-specific information from the Final Safety Analysis Report to calculate the approximate time that operators would have to successfully operate Pump FW-54 following battery depletion conditional upon the success or failure of these two actions. Table 7 documents those times.

Table 7 Time to Steam Generator Dryout During Station Blackout					
Case	Minimize dc Loads	Time to Depletion	Flood Generators	Time for Boil Down	Total Time
1	Success	8 hours	Success	5 hours	13 hours
2	Success	8 hours	Failure	2.6 hours	10.6 hours
3	Failure	2.6 hours	Success	4 hours	6.6 hours
4	Failure	2.6 hours	Failure	2 hours	4.6 hours

The analyst quantified the probability that the operators fail to minimize dc loads in a short period of time using the SPAR-H method described in NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Method." The procedural requirements in Emergency Operating Procedure EOP-00, "Standard Post Trip Actions," and Emergency Operating Procedure Attachment 6, "Minimizing DC Loads," were evaluated. The analyst assumed that this particular action did not require a significant amount of diagnosis because the EOP-00 has a step and multiple notes reminding the operators to take the action when necessary. The analyst adjusted the nominal human error probabilities using the following performance shaping factors:

- Available time was 15 minutes. The analyst assumed that this was just enough time to coordinate with two plant operators and to open breakers in the turbine building and the auxiliary building. Therefore, a factor of 10 was used.

- The stress was assumed to be high because of an ongoing station blackout. Therefore, a factor of 2 was used.

- The complexity was assumed to be moderate because of the coordination needed with plant operators at two different locations and the low lighting during the station blackout conditions. Therefore, a factor of 2 was used.

In addition to these three shaping factors, the analyst adjusted the final result using the Odd's ratio[1] as documented in the draft NUREG, Section 2.5. The probability that operators would fail to minimize dc loads within 15 minutes of a station blackout was calculated to be 3.9×10^{-2}. NOTE: This value was used in calculating the baseline risk of the condition. However, as stated in Assumption 38, the analyst determined that operators would fail to minimize dc loads.

Using a similar approach, the analyst calculated probabilities of human error for each of the required operator actions listed above. The times available, documented in Table 8, were used to modify the performance shaping factors

[1] Odd's ratio is a method of accounting for the number of successes as well as failures when calculating a conditional human error probability. This method of accounting for uncertainties associated with individual performance shaping factors is described in NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Method," and tends to provide a less conservative result.

based on the time operators had to respond to the particular action. The HRA values calculated are documented in Table 8.

Table 8
Operator Failure Probabilities

		Performance Shaping Factors				
Operator Action	Time Available	Time	Stress	Procedure	Experience	Failure Probability
Minimize dc Loads [8, 9]	15 minutes	10	2.0	1.0	1.0	3.9×10^{-2}
Flood S/Gs to 94% [4,9]	2.6 hours	1.0	2.0	1.0	0.5	1.0×10^{-3}
	8 hours	0.1	2.0	1.0	0.5	1.0×10^{-4}
Swap to AFW nozzle and throttle AFW Valves [3,8]	<3 hours	1.0	1.0/2.0[2]	0.5/2.0[5]	1.0/3.0[7]	3.8×10^{-1}
	>4.5 hours	0.1	1.0/2.0[2]	0.5/2.0[5]	1.0/3.0[7]	5.7×10^{-2}
Provide Sufficient Flow [4,9]	2 – 8 hours	0.1	2.0	0.5	1.0	1.0×10^{-4}
Isolate CST [4]	4 hours	1.0/0.1[1]	2.0	0.5/1.0[6]	1.0	1.2×10^{-3}

Notes:

[1] Nominal time was available for diagnosis, but there was barely adequate time to take the action.

[2] Nominal stress was used for diagnosis because of control room environment and verbatim emergency operating procedure compliance. High stress in the field because actions would affect plant safety.

[3] The following items also had the Complexity PSF changed to 0.1 for an obvious diagnosis, and 2.0 for a moderately complex action: minimize dc loads and swap to AFW nozzles.

[4] Complexity values adjusted to indicate an obvious diagnosis based on emergency operating procedure review.

[5] The procedures for diagnosing the need for this step were symptom based, but the procedures for implementation were considered by the analyst to be poor.

[6] The procedures for diagnosing the need for this step were symptom based, but the procedures for implementation were considered by the analyst to be nominal.

[7] The experience of operators is nominal for diagnosing this need, but they do not routinely operate the valve gags in this situation.

[8] The ergonomics were considered poor for swapping the AFW nozzle because an unfamiliar task would have to be done without normal lighting.

[9] These actions did not include a significant amount of diagnosis. Therefore, only the action failure probability was calculated.

The analyst created an event tree to model the actions required to successfully use Pump FW-54 following battery depletion. This event tree, provided as Attachment 1 to this analysis, covered each of the functions required to achieve success, as well as the probability that actions affecting the time available (i.e., minimizing dc loads) would be completed. The analyst used the SPAR to quantify Fault Tree AFW-FW54, "Fort Calhoun PWR G AFW FW-54," and provide a probability that the Pump FW-54 train would fail from stochastic reasons at any time during the accident sequence. The probability of failure was determined to be 3.1×10^{-2}. The analyst then quantified the event tree using the human reliability values listed in Table 8 and the solution from the SPAR fault tree for Pump FW-54 as split fractions. This quantification provided the total failure probability of the Pump FW-54 train during an unrecovered station blackout, upon depletion of the station vital batteries. The probability was quantified as 1.1×10^{-1}.

Given Assumption 38, the depletion of station batteries would take place at 2.6 hours. Therefore, in the event tree in Attachment 1, the Top Event, "Minimize-D," was always failed. The analyst requantified the event tree and determined that the total nonrecovery probability was 4.0×10^{-1} for most cutsets.

The analyst modified the SPAR model to include the attached Event Tree, "FW54 Cooling Following Battery Depletion." The analyst created a transfer to this tree from Event Tree, "Fort Calhoun PWR G Transient," for Sequences 13, 14, and 15.

Treatment of Common Cause Component Failure Probability

Given the unique sets of buses affected by any given postulated fire and the independence of the fire initiators, the analyst determined that the classic alpha-factor method was not appropriate to evaluate the common cause failure probability for the nine vital 480 Vac buses associated with the performance deficiency. As such, in lieu of classical treatment, the analyst quantified the potential that a second independent fire occurs during the time that the plant would likely be maintained above cold shutdown.

As stated in Assumptions 22 and 23, the analyst determined that any postulated independent second fire that occurred within 56 hours (Overlap Time) of the first should be evaluated in combination with the first as an at-power event. Therefore, the analyst calculated the conditional probability that overlapping fires would impact the at-power risk ($P_{Overlap}$) as follows:

$$P_{Overlap} = \text{Overlap Time} * \lambda_{Fire}$$

$$= 56 \text{ hours} \div 8760 \text{ hours/year} * 7.0 \times 10^{-2} \text{ /year}$$

$$= 4.5 \times 10^{-4}$$

Quantification of Conditional Core Damage Probabilities

As stated in Assumptions 1, 2, and 3, the analyst created a more detailed model of the electrical distribution system than that provided in the Fort Calhoun SPAR, Revision 8.15. The changes included appropriate mapping of risk-significance plant equipment and functions supported by these buses. Idaho National Laboratories assisted in incorporating these changes into the SPAR model and validating the impact. The analyst calculated the change in risk related to this performance deficiency using the following method:

The analyst quantified the new model and reestablished a baseline risk for:

Internal Core Damage Frequency	9.3×10^{-6} /year
Single Energetic Switchgear Fire CDF	1.5×10^{-9} /year
Seismically-Induced LOOP CCDP	1.2×10^{-3}

For each of the postulated fires documented in Assumptions 12 and 23 the analyst set the failure probability of the associated vital buses and/or supply breakers to 1.0. Table 10 provides the change sets used for each postulated fire.

The analyst quantified the conditional core damage probability for each of the nine postulated fires. The results are provided in Table 9.

Table 9
Conditional Core Damage Probabilities

Postulated Fire:	Case CCDP:
1B4A	6.4E-05
1B3A	3.1E-05
1B3B	6.1E-05
1B3C	5.8E-05
1B4B	2.3E-05
1B4C	3.8E-05
1B3A-4A	3.1E-05
1B3B-4B	2.3E-05
1B3C-4C	5.8E-05

The analyst then quantified the conditional core damage probability for each combination of two breaker cubicle fires. As stated in Assumption 23, these independently-initiated fires are being evaluated in lieu of a more complex common cause failure evaluation. These results are documented in Table 11.

Table 10 Affected Basic Events for Each of Nine Postulated Fires					
Breaker 1B4A	Breakers 1B4B or BT-1B4B	Breaker 1B4C	Breakers 1B3A or BT-1B3A	Breaker 1B3B	Breakers 1B3C Or BT-1B3C
ACP-BAC-LP-1B4A	ACP-BAC-LP-1B4B	ACP-BAC-LP-1B4C	ACP-BAC-LP-1B3A	ACP-BAC-LP-1B3B	ACP-BAC-LP-1B3C
ACP-BAC-LP-1B3A4A	ACP-BAC-LP-1B3B4B	ACP-BAC-LP-1B3C4C	ACP-BAC-LP-BT1B3A	ACP-BAC-LP-1B3B4B	ACP-BAC-LP-1B3C4C
ACP-CRB-CO-1B3A	ACP-CRB-CO-1B4A	ACP-CRB-CO-1B4A	ACP-CRB-CO-1B3B	ACP-CRB-CO-1B3A	ACP-CRB-CO-1B3A
ACP-CRB-CO-1B4B	ACP-CRB-CO-1B4C	ACP-CRB-CO-1B4B	ACP-CRB-CO-1B3C	ACP-CRB-CO-1B3C	ACP-CRB-CO-1B3B
ACP-CRB-CO-1B4C	ACP-BAC-LP-1A4	ACP-CRB-CO-1B3C	ACP-CRB-CO-1BT1B3C	ACP-CRB-CO-1B4B	ACP-CRB-CO-BT1B3A
ACP-CRB-CO-BT1B3B		ACP-CRB-CO-BT1B3B	ACP-BAC-LP-1A3	ACP-CRB-CO-BT1B3A	ACP-BAC-LP-1A3
ACP-BAC-LP-1A4		ACP-BAC-LP-1A4		ACP-CRB-CO-1BT1B3C	
				ACP-BAC-LP-1A3	

Table 11

Combinations of 2 Fires - Conditional Core Damage Probability

	1B4A	1B3A	1B3B	1B3C	1B4B	1B4C	1B3A-4A	1B3B-4B	1B3C-4C
1B4A		7.4E-02	1.9E-01	1.8E-01	8.4E-05	1.7E-04	7.4E-02	8.4E-05	1.8E-01
1B3A	7.4E-02		8.0E-05	7.1E-05	2.6E-02	2.6E-02		2.6E-02	7.1E-05
1B3B	1.9E-01	8.0E-05		2.5E-04	6.7E-02	6.8E-02	8.0E-05	6.7E-02	2.5E-04
1B3C	1.8E-01	7.1E-05	2.5E-04		6.1E-02	7.7E-02	7.1E-05	6.1E-02	
1B4B	8.4E-05	2.6E-02	6.7E-02	6.1E-02		4.0E-05	2.6E-02		6.1E-02
1B4C	1.7E-04	2.6E-02	6.8E-02	7.7E-02	4.0E-05		2.6E-02	4.0E-05	7.7E-02
1B3A-4A			8.0E-05	7.1E-05	2.6E-02	2.6E-02		2.6E-02	7.1E-05
1B3B-4B	8.4E-05	2.6E-02		6.1E-02		4.0E-05	2.6E-02		2.5E-04
1B3C-4C	1.8E-01	7.1E-05	2.5E-04		6.1E-02		7.1E-05	2.5E-04	

Table 12

Change in Core Damage Frequency for Single Postulated Fires

Postulated Fire:	Exposure Period (days)	Failure Frequency (/year)	Case CCDP	ICCDP
1B4A	365	7.0E-02	6.4E-05	4.5E-06
1B3A	365	7.0E-02	3.1E-05	2.1E-06
1B3B	365	7.0E-02	6.1E-05	4.3E-06
1B3C	365	7.0E-02	5.8E-05	4.1E-06
1B4B	365	7.0E-02	2.3E-05	1.6E-06
1B4C	365	7.0E-02	3.8E-05	2.7E-06
1B3A-4A	365	7.0E-02	3.1E-05	2.1E-06
1B3B-4B	365	7.0E-02	2.3E-05	1.6E-06
1B3C-4C	365	7.0E-02	5.8E-05	4.1E-06

Calculation of Change in Core Damage Frequency

The analyst calculated the change in core damage frequency for each postulated fire as documented in Table 12. The sum of the change in core damage frequencies, 2.7×10^{-5}, is the best estimation of the fire-induced risk for single fire scenarios caused by the subject performance deficiency.

The analyst calculated the change in core damage frequency for each of the 63 postulated fire combinations documented in Table 11. The sum of the change in core damage frequencies, 8.1×10^{-5}, is the best estimation of the fire-induced risk for multiple fire scenarios caused by the subject performance deficiency. Although there is some overlap in the quantification of single and multiple fires, the analyst determined that this dependence was negligible in the final result.

The sum of the fire-induced change in core damage frequencies is 1.1×10^{-4}.

Seismically-Induced Risk

The analyst determined that, for the subject performance deficiency to affect the core damage frequency related to seismic events, the event must result in a fire in at least one of the nine normally-closed 480 Vac breakers. The analyst noted that the dominant risk would result when the seismic event was large enough to result in a loss of offsite power from failure of the switchyard insulators. Additionally, to quantify the increase in core damage frequency (ΔCDF) caused by the inadequately modified/maintained 480 Vac switchgear, the analyst must know the probability that combinations of 480 Vac buses would fail as a result of the performance deficiency, as well as the change in core damage probability assuming that the above postulated conditions occurred.

As such, the analyst evaluated the subject performance deficiency by determining each of the following parameters for any seismic event producing a given range of median acceleration "a" [SE(a)]:

1. The frequency of the seismic event SE(a) ($\lambda_{SE(a)}$) ;
2. The probability that a LOOP occurs during the event ($P_{LOOP\text{-}SE(a)}$);
3. The probability that a given combination of buses fail during the event ($P_{Bus\text{-}SE(a)}$);
4. The number of combinations to be analyzed (Comb);
5. The baseline core damage probability ($CCDP_{SE(a)}$); and
6. The sum of the conditional core damage probabilities ($\Sigma\Delta CCDP_{Bus\text{-}SE(a)}$)

The ΔCDF for the acceleration range in question ($\Delta CDF_{SE(a)}$) can then be quantified as follows:

$$\Delta CDF_{SE(a)} = \lambda_{SE(a)} * P_{LOOP\text{-}SE(a)} * P_{Bus\text{-}SE(a)} * (\Sigma\Delta CCDP_{Bus\text{-}SE(a)} - (Comb * CCDP_{SE(a)}))$$

Given that each range "a" was selected by the analyst specifically to be independent of all other ranges, the total increase in risk, ΔCDF, can be quantified by summing the $\Delta CDF_{SE(a)}$ for each range evaluated as follows:

$$\Delta CDF = \sum_{a=.05}^{8} \Delta CDF_{SE(a)}$$

over the range of SE(a).

Frequency of the Seismic Event

NRC research data indicates that seismic events of 0.05g or less have little to no impact on internal plant equipment. Therefore, the analyst assumed that seismic events less than 0.05g do not directly affect the plant. The analyst assumed that seismic events greater than 8.0g lead to core damage. The analyst, therefore, examined seismic events in the range of 0.05g to 8.0g.

The analyst divided that range of seismic events into segments (called "bins" hereafter). Specifically, seismic events from 0.05-0.08g, 0.08-0.15g, 0.15-0.25g, 0.25-0.30g, 0.30-0.40g, 0.40-0.50g, 0.50-0.65g, 0.65-0.80g, 0.80-1.0g, and 1.0-8.0g defined each bin. These bins were selected from the published hazard curve for the Fort Calhoun Station at frequencies presumed to affect plant equipment differently.

In order to determine the frequency of a seismic event for a specific range of ground motion (g in peak ground acceleration), the analyst used the Risk Assessment of Operation Events (RASP) Handbook, Volume 2, "External Events," and obtained values for the frequency of the seismic event that generates a level of ground motion that exceeds the lower value in each of the bins. The analyst then calculated the difference in these "frequency of exceedance" values to obtain the frequency of seismic events for the binned seismic event ranges.

For example, according to the RASP, the frequency of exceedance for a 0.08g seismic event at Fort Calhoun Station is estimated at 5.6×10^{-4}/yr and a 0.15g seismic event at 2.3×10^{-4}/yr. The frequency of seismic events with median acceleration in the range of 0.08g to 0.15g [$SE_{(0.08\text{-}0.15)}$] equals the difference, or 3.2×10^{-4}/yr.

Probability of a Loss of Offsite Power

The analyst assumed that a seismic event severe enough to break the ceramic insulators on the transmission lines will cause an unrecoverable loss of offsite power.

The analyst obtained data on switchyard components from the Risk Assessment of Operating Events Handbook; Volume 2, "External Events," Revision 4, which referenced generic fragility values listed in:

> NUREG/CR-6544, "Methodology for Analyzing Precursors to Earthquake-Initiated and Fire-Initiated Accident Sequences," April 1998; and
>
> NUREG/CR-4550, Vols 3 and 4 part 3, "Analysis of Core Damage Frequency: Surry / Peach Bottom," 1986

The references describe the mean failure probability for various equipment using the following equation:

$$P_{fail(a)} = \Phi \left[\ln(a/a_m) / (\beta_r^2 + \beta_u^2)^{1/2} \right]$$

Where Φ is the standard normal cumulative distribution function and

$a =$ median acceleration level of the seismic event;
$a_m =$ median of the component fragility;
$\beta_r =$ logarithmic standard deviation representing random uncertainty;
$\beta_u =$ logarithmic standard deviation representing systematic or modeling uncertainty.

In order to calculate the LOOP probability given a seismic event the analyst used the following generic seismic fragilities:

$a_m = 0.3g$
$\beta_r = 0.30$
$\beta_u = 0.45$

Using the above normal cumulative distribution function equation the analyst determined the conditional probability of a LOOP given a seismic event. For each of the bins the calculation was performed substituting for the variable "a" (peak ground acceleration) the acceleration levels obtained from the bins described above. Table 13 shows the results of the calculation for various acceleration levels.

Table 13
Peak Ground Acceleration/Probability of LOOP

0.05g	2.0E-3		0.3g	6.0E-1		0.8g	9.8E-1
0.15g	2.1E-1		0.5g	8.8E-1			

Given Assumptions 30 and 31, the independent probability that any given breaker cubicle would fail within an associated bin would be equal to the probability of a LOOP. Continuing this logic, the failure probability of any two breaker cubicles would be the square of the conditional LOOP probability for the bin.

Conditional Change in Core Damage Probability

The analyst evaluated the spectrum of seismic initiators to determine the resultant impact on the reliability and availability of mitigating systems affecting the subject performance deficiency.

The analyst used the Fort Calhoun Station Revision 8.15 SPAR Model (as modified), to perform the evaluations. The analyst first created a baseline case by setting the initiating event probability for a LOOP to 1.0 and all other initiating event probabilities in the SPAR model to zero. Offsite power was assumed to be

nonrecoverable following seismic events that break the ceramic insulators (low fragility components) on the transmission lines. Therefore, the analyst set the nonrecovery probabilities for offsite power to 1.0. The modified SPAR model quantified the resultant conditional core damage frequency as 1.2×10^{-3}, which represented the baseline case that is used in the above equation.

The SPAR Model was then used to quantify the case values using the change sets described in Table 10. The change in conditional core damage probability was calculated for each postulated single fire within each bin and for each combination of two fires designated in Table 11. The analyst noted that the seismic failure of multiple breakers would be a likely scenario. However, these were not evaluated given the significant amount of effort required to perform such calculations and that the change in core damage frequency for postulated single seismically-induced fires already exceeded the Yellow/Red Threshold.

Phase 3 Seismic Results

Considering the factors described above for each bin, namely,

- The frequency of the seismic event;
- The probability that a LOOP occurs during the event;
- The probability that a given vital bus would fail during the event;
- The baseline core damage probability; and
- The conditional core damage probabilities

The total increase in seismically-induced risk, $\Delta CDF_{Seismic}$, can be quantified by summing the $\Delta CDF_{SE(a)}$ for each bin as follows:

$$\Delta CDF = \sum_{a=.05}^{8} \Delta CDF_{SE(a)}$$

Given the assumptions, the total increase in core damage frequency was estimated to be about 2.9×10^{-4} from single and double initiated fires for seismic events ranging from 0.05g to 8.0g.

High Winds, Floods, and Other External Events

The analyst reviewed the licensee's Individual Plant Examination of External Events and determined that no other credible scenarios initiated by high winds, floods, fire, and other external events could initiate a failure of the subject breaker cubicles. Therefore, the analyst concluded that external events other than fires initiated by the performance deficiency and/or seismic events are not significant contributors to risk for this finding.

Large Early Release Frequency

In accordance with the guidance in NRC Inspection Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process," this finding would not involve a significant increase in risk of a large, early release of radiation because Fort Calhoun has a large, dry containment and the dominant

sequences contributing to the change in the core damage frequency did not involve either a steam generator tube rupture or an inter-system loss of coolant accident.

Qualitative Considerations of Risk

The analyst noted that several factors that affected the risk of the subject postulated fires were not quantified because practical matters made them significantly more difficult to quantify. They included the following:

1. Shutdown Risk

   As documented in Assumptions 33 and 34, the analyst noted that additional risk would be accumulated at the plant following the fires postulated in this analysis. 480 Vac loads at Fort Calhoun Station include component cooling water, containment spray, spent fuel pool cooling and other support systems necessary for maintaining the reactor and/or spent fuel pool cool during shutdown conditions.

   The long-lasting effects of a major fire continue to impact plant operations and require additional operator actions throughout the shutdown period while the bus or buses are being repaired. Additionally, a loss of shutdown cooling during critical shutdown conditions as a result of a postulated fire would cause significant increase in the instantaneous risk of the shutdown reactor.

   The analyst determined that these impacts were too numerous to individually identify and the current shutdown risk tools do not lend themselves to assess the impacts quantitatively. However, the analyst noted that these risks should be considered in making a risk-informed decision.

   To estimate the impact of this risk, the analyst evaluated the impact of loss of component cooling water pumps from postulated 480 volt bus fires. The following assumptions were made:

   a. The impact on Component Cooling Water would be 98 days. This was based on the bus fire occurring on June 7 and the licensee declaring the remaining buses inoperable on September 13.
   b. The results from the San Onofre Shutdown SPAR model were good enough to approximate this risk, given that the vast majority of risk impact was the result of human error and not additional equipment failures.
   c. Each postulated fire scenario that affected one or more component cooling water pumps were quantified.

   The estimated incremental conditional core damage probability was 6.9×10^{-5}. The analyst determined that this value was not accurate enough to meet the quantitative requirements of the significance determination process. However, the actual probability would be added to the final risk determination were it known accurately. This indicates

that shutdown risk during the repair time following a postulated fire would be significant with respect to the subject finding.

2. <u>Seismic Risk from 3 or More Postulated Fires</u>

As documented in Assumption 32, failures of more than two breaker cradles following a seismic event are possible. However, the evaluation of the risk for these scenarios would become prohibitive based on the large number of scenarios that would be possible and would not be expected to contribute significantly to the overall risk.

The analyst noted that the addition of multiple fire scenarios can add combinations that result in conditional core damage probabilities of 1.0, losses of residual heat removal at shutdown, complete losses of spent fuel pool cooling, as well as failures of all higher pressure injection capability.

As stated above, the analyst determined that these impacts were too numerous and prohibitive to individually evaluate quantitatively. However, the analyst noted that these risks should be considered in making a risk-informed decision.

To better understand the risk of this contributor, the analyst evaluated the range of risk impact for a seismic event causing three breaker cubicle fires. The analyst utilized the modified SPAR model to determine the risk of fires involving Buses 1B3A, 1B3B, and 1B3C-4C. This was considered to be the lowest possible risk from a combination of 3 fires. The conditional core damage probability for these fires was 7.27×10^{-2}. The analyst then quantified the conditional core damage probability for postulated fires in Buses 1B4A, 1B3B, and 1B3C-4C. This combination resulting in the highest possible risk was quantified as 1.0.

The analyst then performed a seismic evaluation assuming that all fires evaluated resulted in the conditional core damage probabilities listed above. This resulted in a range of 3.4×10^{-5} to 4.7×10^{-4}. The analyst noted that neither the low end nor the high could be the result, but only that the result would lay somewhere between the two. This risk would be additive to the best estimate value indicating that the risk from a seismic event causing three or more breaker cubicle failures would be significant with respect to the subject finding.

3. <u>Risk to Fuel in the Spent Fuel Pool</u>

As documented in Assumption 35, the 480 Vac system at Fort Calhoun Station supports the cooling of the spent fuel pool. As a result, the subject performance deficiency impacts the risk of core damage in the spent fuel pool. As few as two postulated fires could result in the complete loss of plant process equipment designed to cool the spent fuel pool.

The current risk tools available to the analyst do not lend themselves to assess the impacts of a loss of spent fuel pool cooling quantitatively. However, the analyst noted that these risks should be considered in making a risk-informed decision.

The analyst noted that the risk to the spent fuel pool would be substantially less than that for the shutdown reactor. This is primarily because of the capability to feed and bleed the pool and the acceptability of almost any water source. Therefore, while this risk would be additive, it would not be significant to the subject evaluation.

4. <u>Potential Loss of Control Power</u>

As stated in Assumption 37, for some fire scenarios, a fire in one bus will affect the dc control power for buses in the opposite train. For example, a fire in Bus 1B3B would likely destroy Manual Transfer Switch 1B3B-4B-MTS. This switch controls dc power to Buses 1B4A, 1B4B, 1B3B-4B, and 1B4C. Loss of control power to these buses will, at a minimum, require local manual operation of all the automatic circuit breakers, including feeder breakers and bus-tie breakers. Also, this failure would likely impact the undervoltage relays on the 480 buses and might impact the indicator functionality.

As a result, manual operations of all breakers would be required for operator responses, increasing the risk associated with the finding. The analyst noted that the current SPAR model does not include individual switches and load breakers, nor does it map the effects of dc control power. However, there is additional risk resulting from the extra work load on operators responding to the postulated events that was not calculated in this evaluation. However, the analyst noted that these risks should be considered in making a risk-informed decision.

To better understand the potential impact of this factor, the analyst reran the worst case fire scenario using twice the nonrecovery terms. The increase in risk was less than twice the original conditional core damage probability. Therefore, while this risk would be additive, it would not be significant to the subject evaluation.

5. <u>Calculation of Breaker Cubicle Failure Rate</u>

As stated in Assumption 36, the failure frequency was calculated as a straight-line rate for the subject breaker cubicles. However, the actual failure frequency was most likely some form of an exponential curve. As such, the failure frequency for the last few months of the exposure period would have been higher than the average failure frequency as calculated. The quantified risk is proportional to the failure rate. Therefore, the risk is likely higher and may be substantially higher than quantified.

Because the actual slope of the failure rate curve is unknown, the additional risk resulting from the approximated failure rate could not be

quantified. However, the analyst noted that these risks should be considered in making a risk-informed decision.

To better understand the risk of this contributor, the analyst evaluated the result given a failure rate that was twice the calculated rate with 1/4 the total exposure time. The resulting total incremental conditional core damage probability was 3.4×10^{-4}. Being 3 times the best estimate value for independent fires, this indicated that, if the failure frequency could be quantified as a decaying rate, the results would be significant with respect to the subject finding.

Sensitivities

The analyst performed a sensitivity study for two of the dominant assumptions in this evaluation. The following assessments were conducted:

1. Assumptions 30 and 31 indicate that the subject performance deficiency could be affected by seismic activity and an approximate seismic fragility at which a breaker cradle would fail. The analyst reevaluated the risk given the following three changes to these assumptions:

   a. Breaker cradles would fail with a fragility similar to the generic functional failure of electrical components from chatter (approximately 1.0g pga);

   b. Breaker cradles would not fail from a seismic event; and

   c. Breaker cradles would fail upon a seismically induced loss of coolant accident.

2. Assumptions 22 and 23 indicate that two independent fires could occur at times close enough to impact the risk of the at-power plant. The fundamental assumption provided that the frequency of these fires would be evaluated over a 56-hour period. The analyst reevaluated the risk of these two fire scenarios given a 24-hour period and a 72-hour period.

The results of this sensitivity analysis are provided in Table 14.

Table 14
Results of Sensitivity Studies

Change Evaluated	Incremental Conditional Core Damage Probability		
	Independent Fire	Seismic	Total
Best Estimate Seismic Analysis	1.1×10^{-4}	3.3×10^{-4}	[redacted]
Nominal Chatter Functional Failure		6.1×10^{-5}	
No Seismic Failure		0.0	
Failure upon Seismic LOOP		8.1×10^{-4}	
Two fires in 56 hours (Best Estimate)	1.1×10^{-4}		
Two fires in 24 hours	6.2×10^{-5}		
Two fires in 72 hours	1.5×10^{-4}		
Highest Combination	1.5×10^{-4}	8.1×10^{-4}	
Lowest Combination	6.2×10^{-5}	0.0	6.2×10^{-5}

Conclusions

The senior reactor analyst completed a Phase 3 analysis using the plant-specific Standardized Plant Analysis Risk Model for Fort Calhoun, Revision 3.45, the licensee's Individual Plant Examination of External Events, and hand calculations. The exposure period of 1 year represented the maximum exposure time allowable in the significance determination process. The analyst estimated the initiating event likelihood for a single fire of 7.0×10^{-2}/year. The analysis covered the risk affected by the performance deficiency for postulated fires of any of the nine normally-closed breakers including the potential for two independent fire initiators. The resulting change in core damage frequency (ΔCDF) was 1.1×10^{-4}. Additionally, seismically-induced fires were postulated based on the characteristics of the performance deficiency. The quantified ΔCDF for seismically-induced fires was 3.3×10^{-4}.

Finally, the analyst determined that the finding did not involve a significant increase in the risk of a large, early release of radiation. The final result was calculated to be 4×10^{-4} indicating that the finding was of high safety significance (Red).

The analyst performed sensitivity studies indicating that only the most negative combination of assumption changes provided a value in the Yellow region. 95.7 percent of the risk range from these sensitivities was in the Red region. Additionally, qualitative considerations suggest that the actual risk is higher than this calculated value, and could be Red of their own right if properly quantified.

Licensee's Proposed Modeling Assumptions

To facilitate better communications on this evaluation, the licensee provided the analyst with a set of proposed modeling assumptions (draft) dated November 14, 2011. The analyst reviewed the licensee's assumptions to ensure that

appropriate treatment was considered. The following addresses each of the licensee's draft assumptions and how they were dispositioned:

1. The licensee assumed that potential breaker fire consequences should be modeled for the nine normally-closed 480V breakers that were modified in 2009.

   We agree. This is documented in Assumptions 7 and 12.

2. The licensee reserved the right to challenge the fire frequency. They stated that not just Fort Calhoun, but any applicable industry data should be used.

   We agree. However, neither the licensee nor our analysts have found any additional data. Additionally, the frequency is probably not linear, so we could potentially justify an even higher failure rate for the year assessed.

   The licensee informed us on January 12, 2012, that they were unable to identify additional data applicable to this finding.

3. The licensee assumed that the exposure time should be 1 year and evaluated for at-power operation.

   We agree. This is documented in Assumptions 5, 8 and 9.

4. The licensee stated that the total mission time should be 24 hours. This is opposed to our Assumptions 22 and 23.

   We disagree. While 24 hours is a classical mission time and was used for the actual fire response equipment, Assumption 23 clearly states that the 56 hours is used in an attempt to better quantify the common cause failure probability. The licensee did not suggest a different method for applying common cause. However, it is clear that common cause factors were in play.

   During a January 12, 2012 phone call with the licensee's PRA group, we agreed to disagree on this issue.

5. The licensee assumed that postulated fires of the bus main breaker or bus-tie breaker would result in failure of the adjacent bus or buses. Also, a 480 Vac main bus breaker fire adjacent to a normally-open bus tie breaker was assumed to induce a fault on the island-bus side of the normally-open bus tie breaker and induce a trip of the opposite main bus breaker.

   We agree with the licensee's definitions of which buses would fail and which would be tripped, as documented in Assumptions 12 through 15.

   However, their analyst assumed that cross-tie capability could be used to restore buses to power. The NRC analyst noted that conditions would not

permit operators to simply close a breaker following tripping it to extinguish a fire. Therefore, the probability of having a bus available is much lower than nominal. Additionally, the analyst determined that most of the core damage sequences included a loss of opposite train power. Given a loss of power on the opposite train, power cannot be restored to the switchgear by cross tying the buses.

During a January 12, 2012 phone call with the licensee's PRA group, they stated that their modeling the cross-tie capability did not significantly decrease the calculated risk of this finding. Therefore, the analyst's concern was alleviated and the NRC did not model the bus cross-ties.

6. The licensee assumed that, following a postulated fire;

   a. Block valves would be closed
   b. Reactor would be manually tripped
   c. The associated 4160 Vac buses would be de-energized

   The licensee stated that individual supply breakers may or may not be tripped and that load breakers would not be tripped.

   We agree. This is documented in Assumptions 18, 20 and 21.

7. The licensee assumed that a 480 Vac island-bus fault will trip the 480 Vac main bus breaker that is feeding the island bus.

   We agree. This is documented in Assumption 11.

8. The licensee stated that operator actions to minimize loads would be ineffective for the dc bus in the same room as the postulated fire. NOTE: FCS vital batteries will last 2.6 hours without minimizing dc loads. The first step will increase battery life to 4 hours. The second step will increase battery life to 8 hours.

   We agree with the licensee's assumption, as documented in Assumption 38. However, the analyst also assumes that, the Halon in the opposite train switchgear room would make load minimization ineffective for the opposite train dc bus.

   The NRC inspectors walked down the dc load minimization procedure. The major loads were required to be stripped within 15 minutes; however, most of these breakers are inside the fire area and/or an area filled with Halon. The inspectors noted that, during the actual fire, plant personnel (other than fire brigade) did not enter these rooms for over 2-1/2 hours. Therefore, the analyst did not give credit for minimizing dc loads, and assumed that the vital batteries would deplete in 2.6 hours.

   During a January 12, 2012 phone call with the licensee's PRA group, the licensee stated that they gave credit for minimization of dc loads on the opposite train on all single fire scenarios and gave credit for minimizing

loads for all two fire scenarios if the second fire was more than 2 hours after the first.

We disagreed with this approach. It is not clear that the operators would minimize dc loads on the dc train that was unaffected by the fire because that train would continue to be supplied by a battery charger. Additionally, after the first fire was extinguished, there is a strong possibility that nonvital loads would be reapplied to the unaffected train. These loads included plant lighting and turbine-generator auxiliaries.

9. The license made the following assumptions regarding recovery:

    a. Local reset of tripped breakers only applies to the twelve 480 Vac supply breakers upon breaker trip due to fault.

       We agree. No penalty was modeled for other breakers.

    b. Re-energization of manually de-energized 4160 Vac bus and associated 4160 and/or 480 Vac loads can be performed from the main control room.

       We agree. The nonrecovery values for the 4160 Vac buses reflect the better ability to re-energize these buses. Additionally, no penalty was modeled for the failure to energize any bus loads, once the primary bus was energized.

    c. Energizing a 480 Vac bus from the opposite side through the island bus can be done from the main control room.

       We agree. However, most core damage scenarios include a failure of the opposite train of power. Therefore, energizing a bus from the opposite side would likely be reflected in a success sequence.

    d. Bus 1B3C can be energized via 13.8 kV Transformer T1B-3C-1.

       The analyst walked down the procedure for energizing Bus 1B3C via 13.8 kV Transformer T1B-3C-1. The analyst noted that most of the steps in the procedure required access to the East Switchgear room and one step required opening a fire barrier door between the East and West Switchgear rooms. Following a postulated fire, one room would be filled with smoke while the other was filled with Halon. Therefore, the analyst determined that this procedure could not be performed before battery depletion.

       Additionally, the analyst noted that postulated fires in Buses 1B3C, 1B3C-4C, and 1B4C would prevent the performance of this procedure at any time following the fire and that the 13.8 kV supply would not survive seismic event.

       During a January 12, 2012 phone call with the licensee's PRA group, the licensee stated that their dependency review indicated that this

recovery was likely to be superseded by the recovery discussed under Item e. Therefore, they chose not to credit this recovery.

e. Steam Generator level indication will be available via the Distributed Control System following battery depletion.

   The analyst observed a simulator run that resulted in a station blackout with battery depletion. The operators noted that the steam generator level indication, powered by the 13.8 kV system did not appear to provide valid level indication. The licensee has not responded yet on this issue. However, the analyst determined that the availability of this indication was not relevant, given the credit provided for the use of portable steam generator level indication following battery depletion discussed under Section f.

f. Use of portable steam generator level indication is available.

   We agree. The analyst walked down the procedure for determining steam generator level following battery depletion. While the communications aspects were somewhat awkward, the analyst determined that the procedure was sound and could provide adequate level indication.

   The availability of level indication was a necessary condition for the recovery documented under "Adjustments to SPAR."

10. The licensee stated that they did not believe that the breaker/cradle assemblies would fail during a seismic event.

    We disagree. The inspectors noted that the root-cause analysis for the June, 2011 event stated that the fire resulted from insufficient cradle connections to the silver plated areas of the copper bus bar stabs, and the presence of hardened grease resulting in high-resistance connections. The licensee provided an analysis indicating that the breaker/cradle assembly was seismically qualified. However, the original evaluation and testing was performed with properly plated stabs and proper cradle connections to the bus bars. This evaluation was not clearly applicable to the condition of the cradles following the performance deficiency.

    Additionally, the vendors disagreed with the conclusions in the licensee's root-cause. The vendors concluded that the fire likely started in the bus compartment area, which contained bolted connections and welded bus bars, and not the breaker compartment. The bus compartment area had not been opened, inspected, or cleaned in at least 30 years. Bolted connections, hardened grease, and housekeeping issues are all items that make a switchgear more susceptible to seismic events.

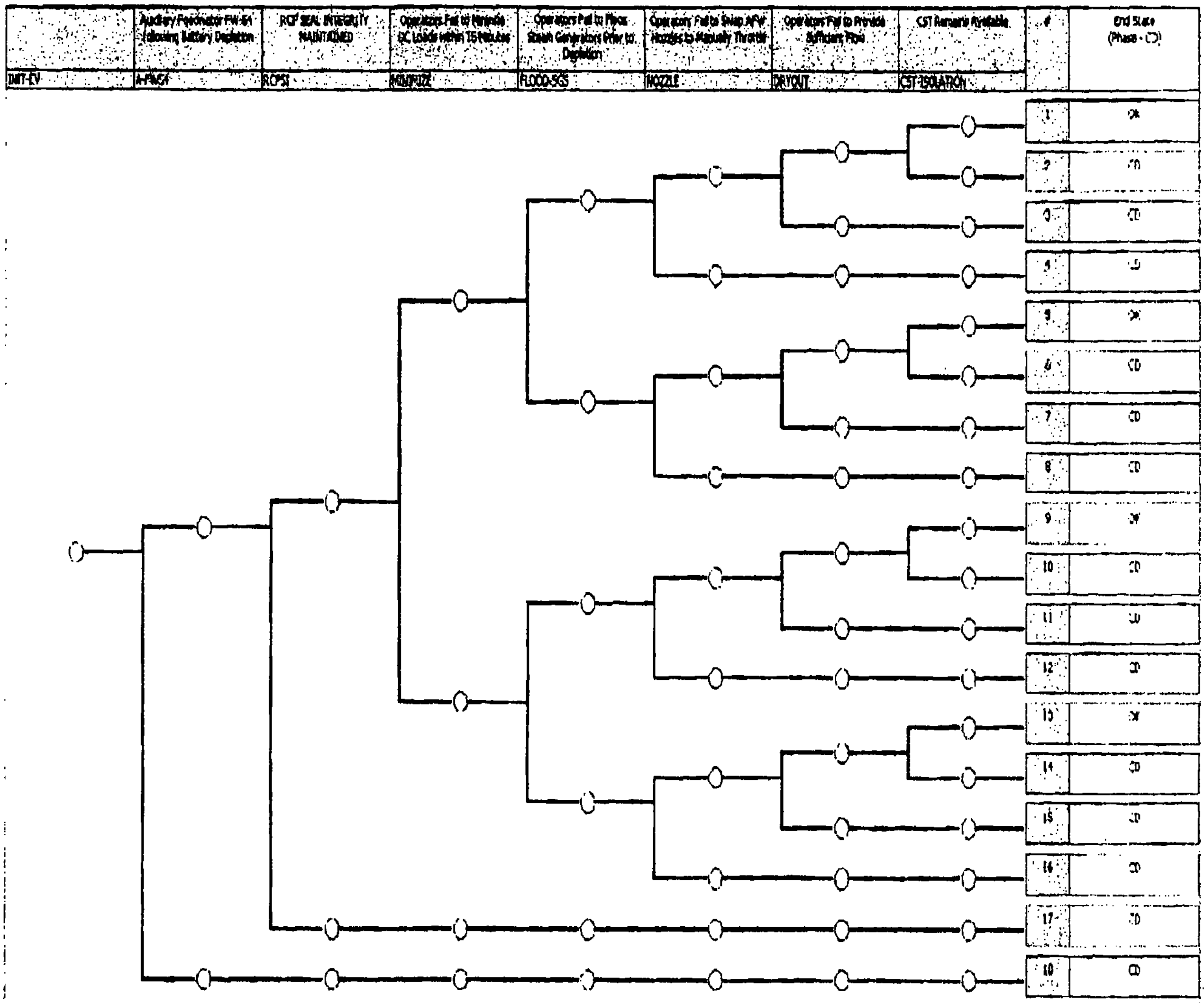
    During a January 12, 2012 phone call with the licensee's PRA group, we agreed to disagree on this issue.

11. On a phone call, licensee PRA group representatives stated that one reason their Assumption 9.e was important was that the availability of steam generator level indication allowed them to take credit for Turbine-Driven Auxiliary Feedwater Pump 10 continuing to run after vital battery depletion.

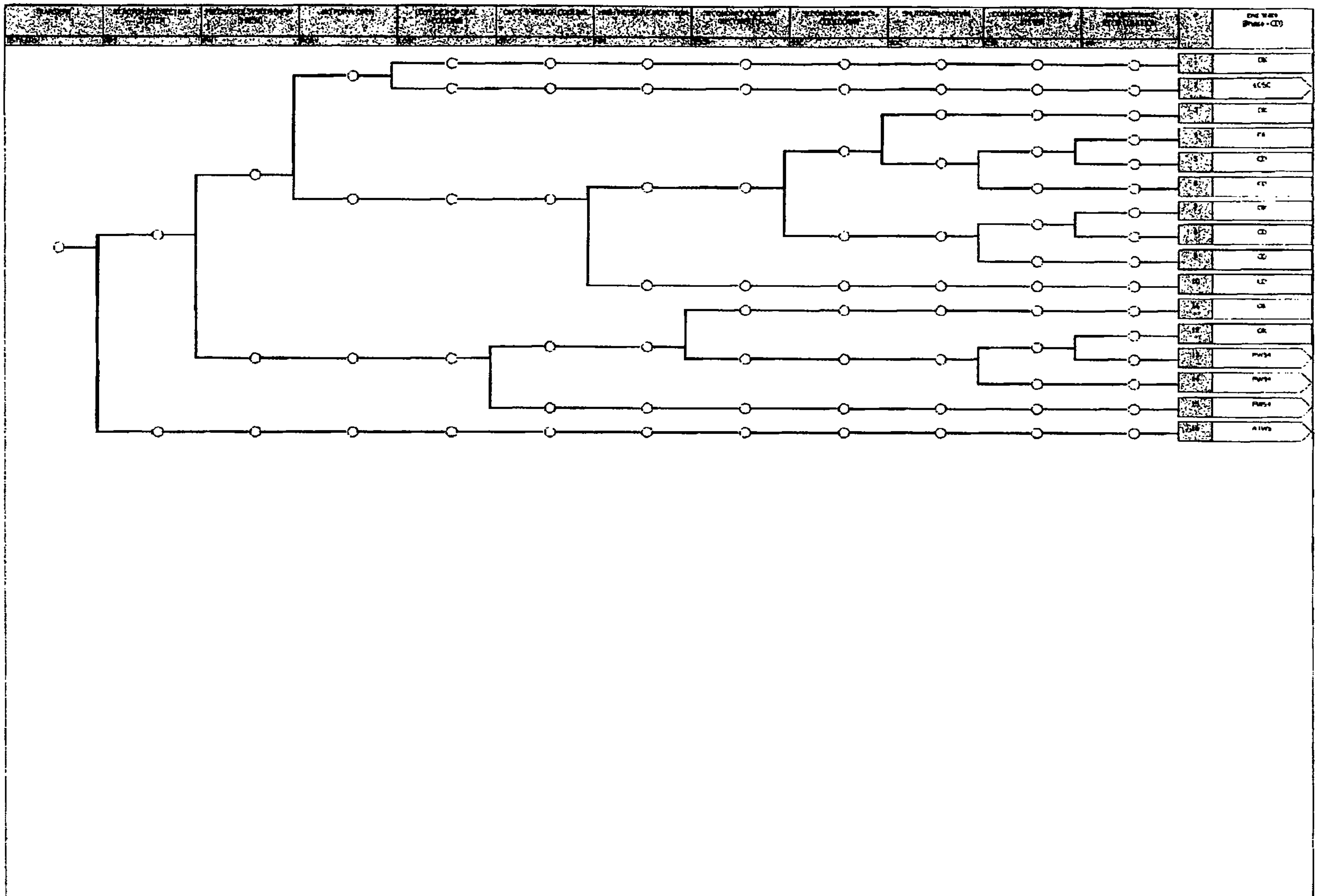
    The NRC analyst stated that the SPAR rules which apply to the significance determination process assume that plants go to core damage following vital battery depletion. As discussed under "Adjustments to the SPAR," credit was given to Diesel-Driven Auxiliary Feedwater Pump 54 after vital battery depletion because of the unique configuration of that pump at Fort Calhoun. However, the analyst noted the following reasons for not crediting Turbine-Driven Auxiliary Feedwater Pump 10 under similar conditions:

    1. There is a lot of dependence between using the turbine-driven auxiliary feedwater pump and the diesel-driven pump for use in station blackout following battery depletion
    2. Given credit for the turbine-driven auxiliary feedwater pump would be in conflict with the SPAR rules. Neither the NRC nor INL gives credit for turbine-driven pumps after battery depletion in the significance determination process. As such, all plant SPAR models indicate that the reactor will proceed to core damage upon vital battery depletion. Here is a listing of some of the documented reasons for this rule:

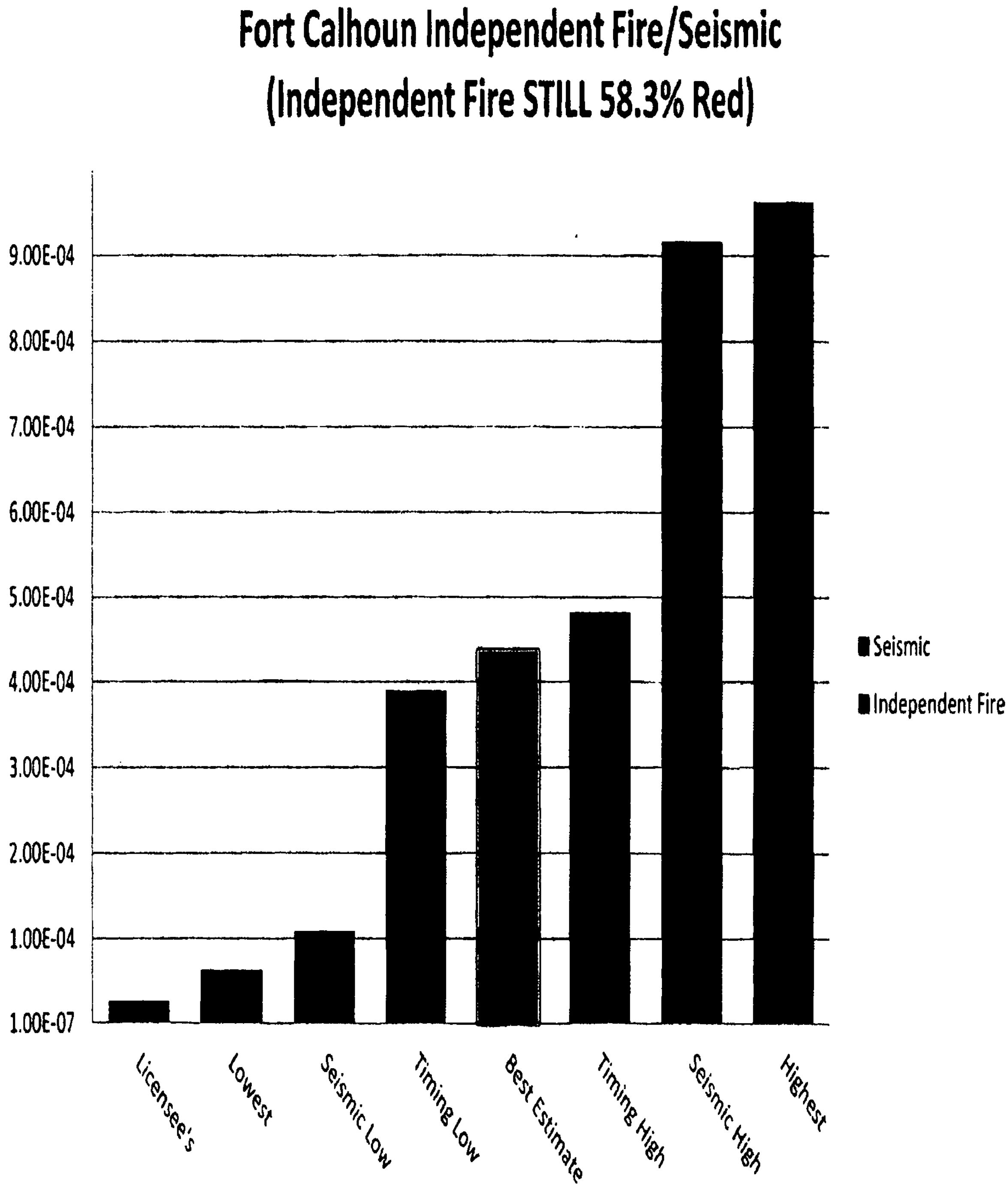
        a. No room cooling would be available
        b. No cooling would be available to the seal condenser
        c. No pressure indication would be available
        d. Difficulty relaying level indication to operators of pump controls
        e. Controls are in high temperature/low light area
        f. Flow path difficult to control with air-operated valves
        g. No capability of "black" operation for venting containment
        h. Fort Calhoun has small emergency feedwater tank



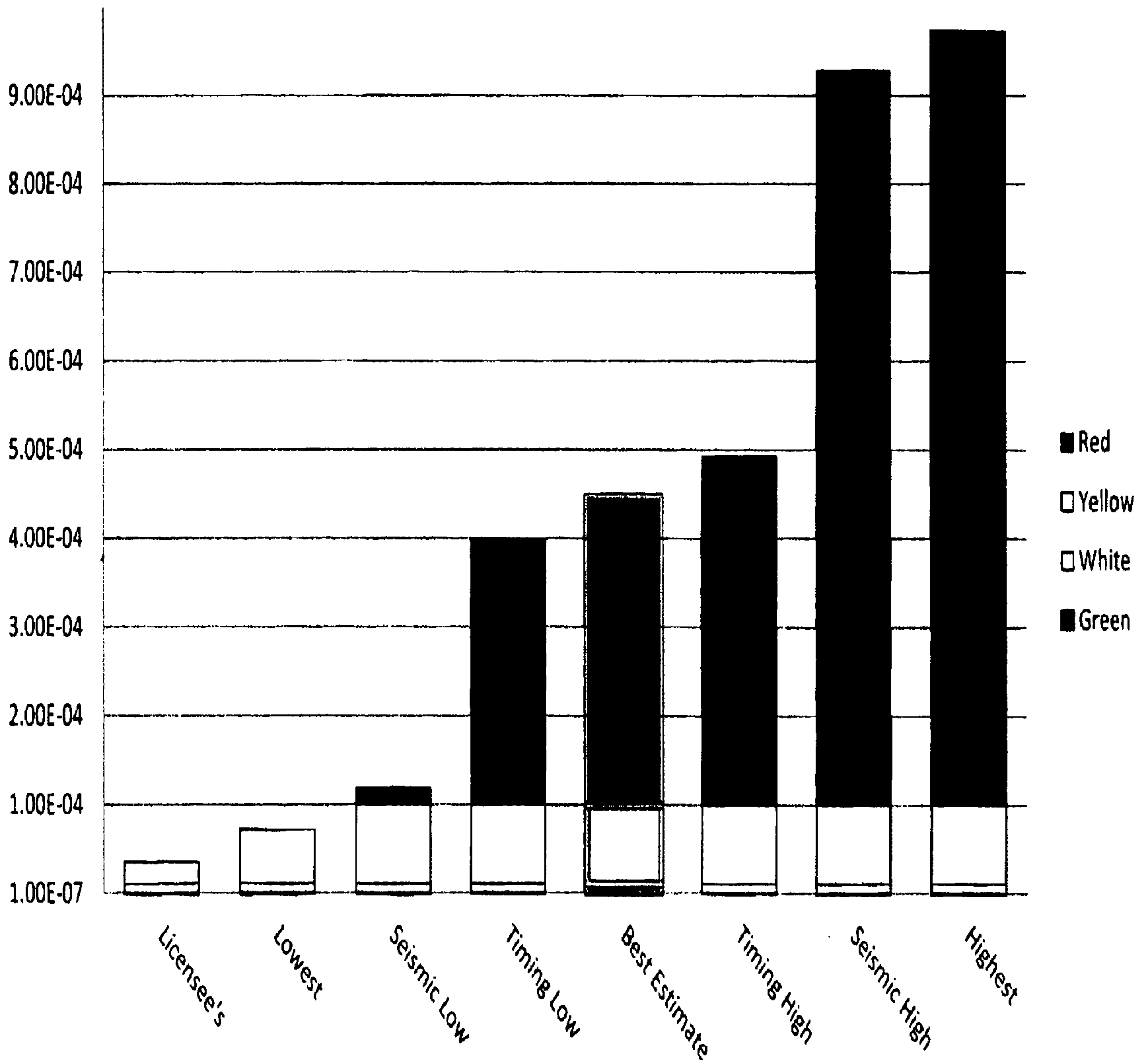
FW54 FW54 Cooling Following Battery Depletion Page 1 of 1



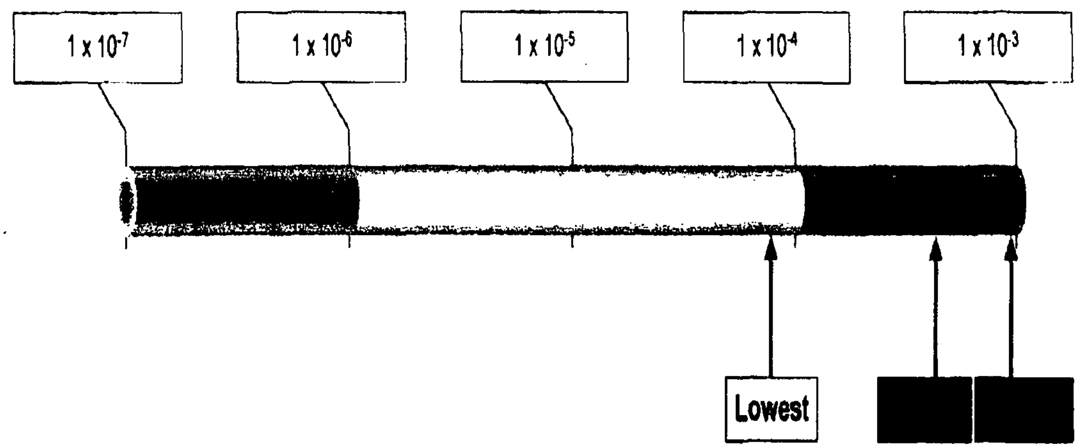
TRANS Fort Calhoun PWR G transient Page 1 of 1


Fort Calhoun Independent Fire/Seismic
(Independent Fire STILL 58.3% Red)
9.00E-04
8.00E-04
7.00E-04
6.00E-04
5.00E-04
4.00E-04
3.00E-04
2.00E-04
1.00E-04
1.00E-07
Licensee's
Lowest
Seismic Low
Timing Low
Best Estimate
Timing High
Seismic High
Highest
Seismic
Independent Fire

Fort Calhoun Breaker Fire Sensitivities
95.7 Percent Red



Fort Calhoun Breaker Fire Risk "Egg"



Attachment

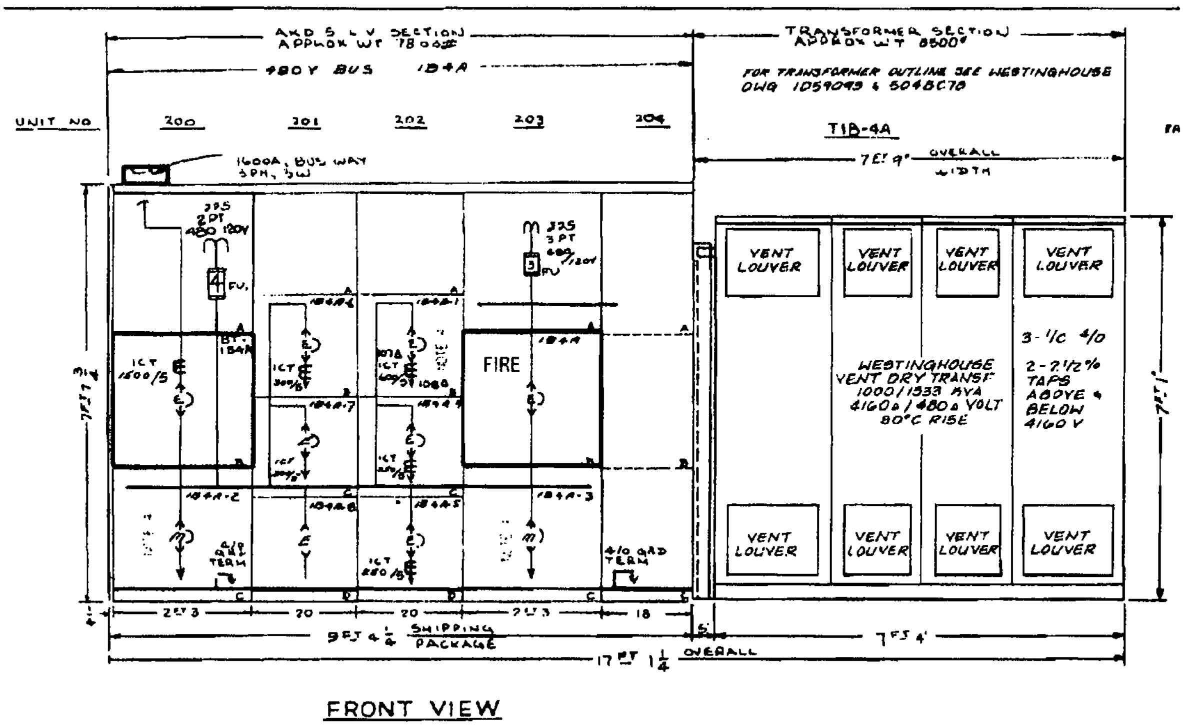
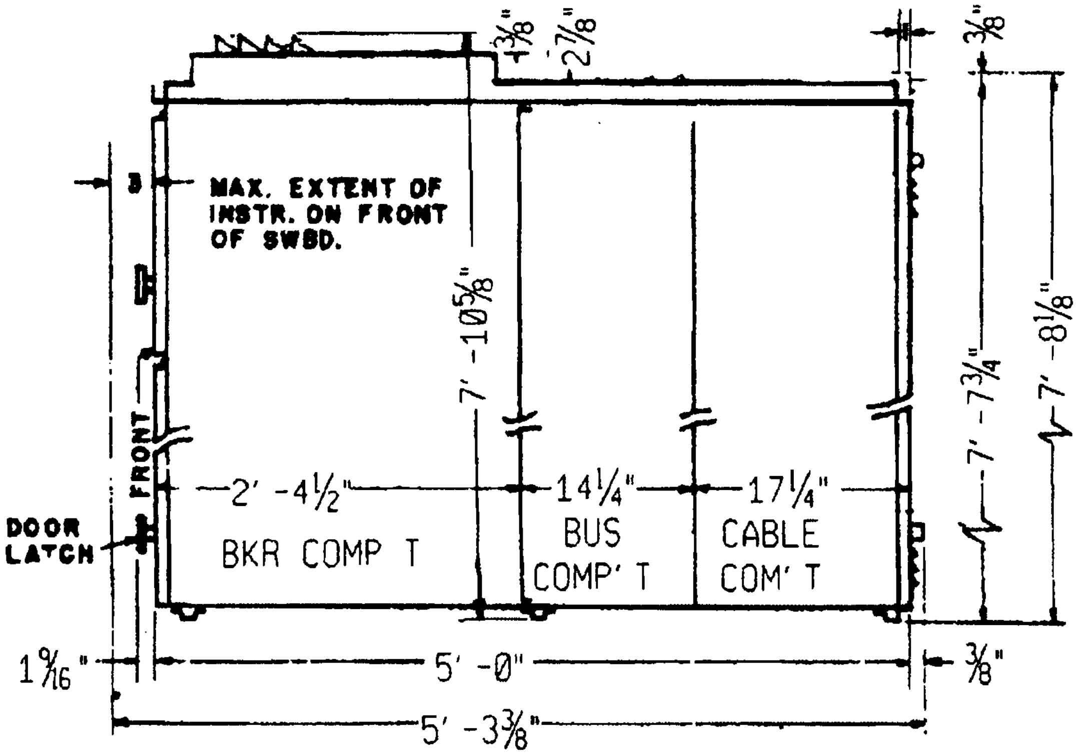


Figure 1: 1B4A Switchgear - Outline



SIDE VIEW-TYPICAL AKD-5 UNIT

Figure 2: Side View of Switchgear

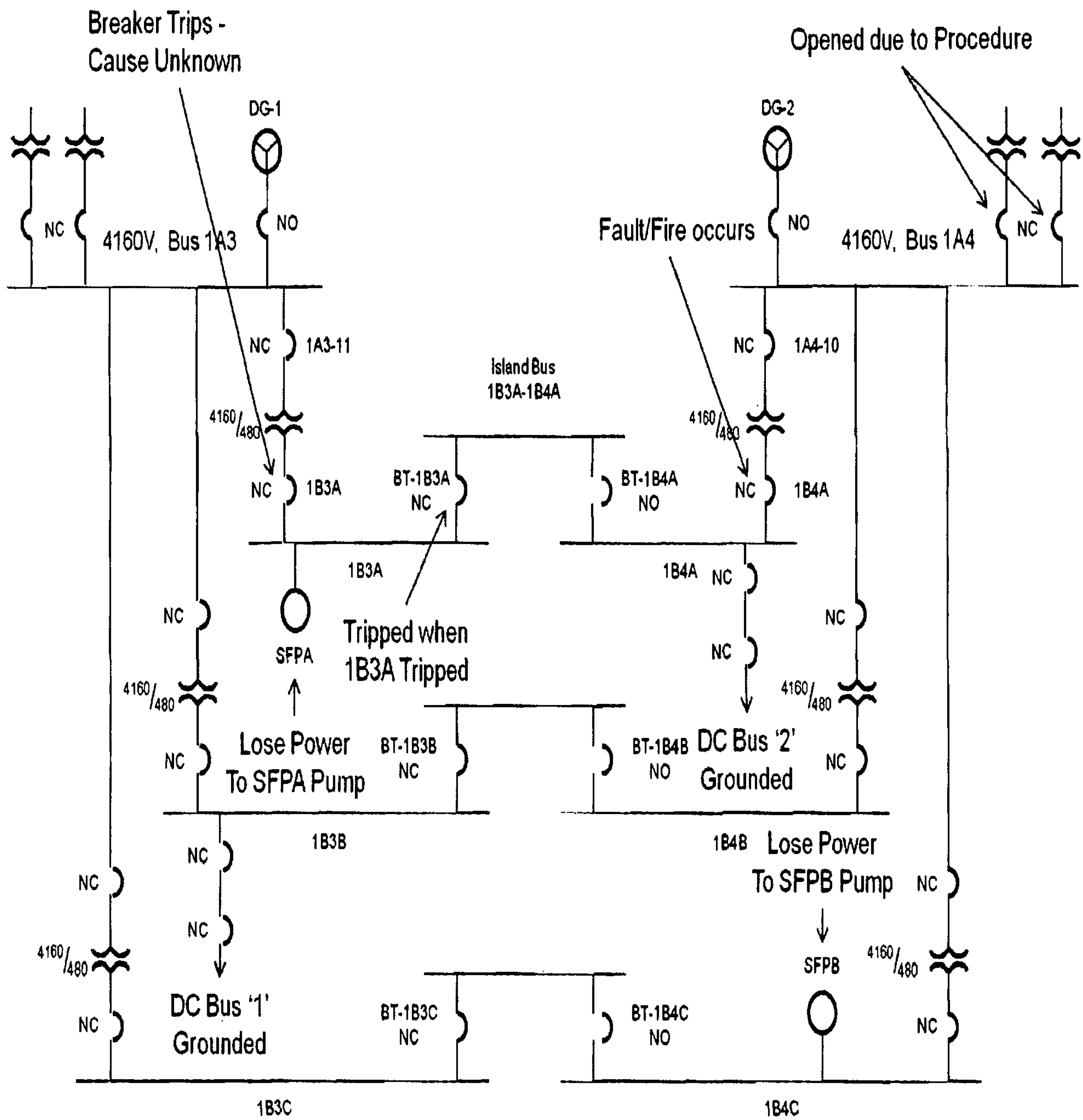
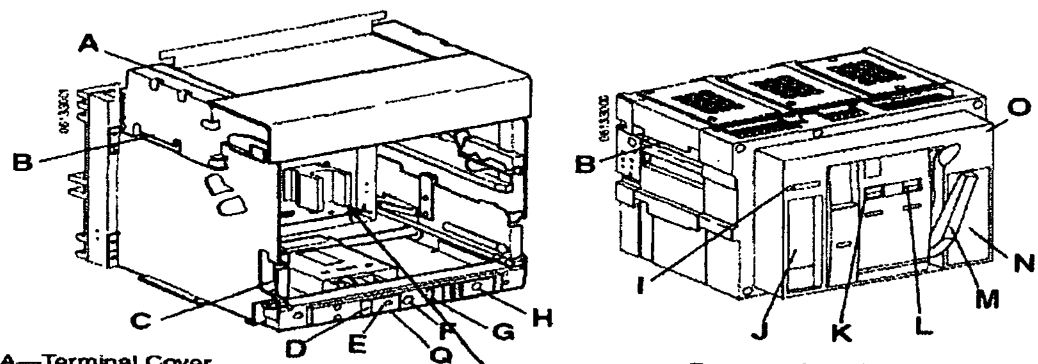


Figure 3: 480V Electrical Distribution System



Cradle

Drawout Circuit Breaker

A—Terminal Cover
B—Lifting Flanges
C—Extension Rail Handle
D—Padlock Provision
E—Stop Release Button
F—Racking Handle Insertion Opening
G—Position Indicator
H—Racking Handle Storage Space
I—Fault Trip Reset Button
J—Trip Unit
K—Push to Open Button
L—Push to Close Button
M—Charging Handle
N—Faceplate
O—Accessory Cover
P—Fixed Mounting Brackets
Q—Cradle Date Code

Cradle stabs. Breaker connects here.

Figure 4: Cradle and Breaker Drawing

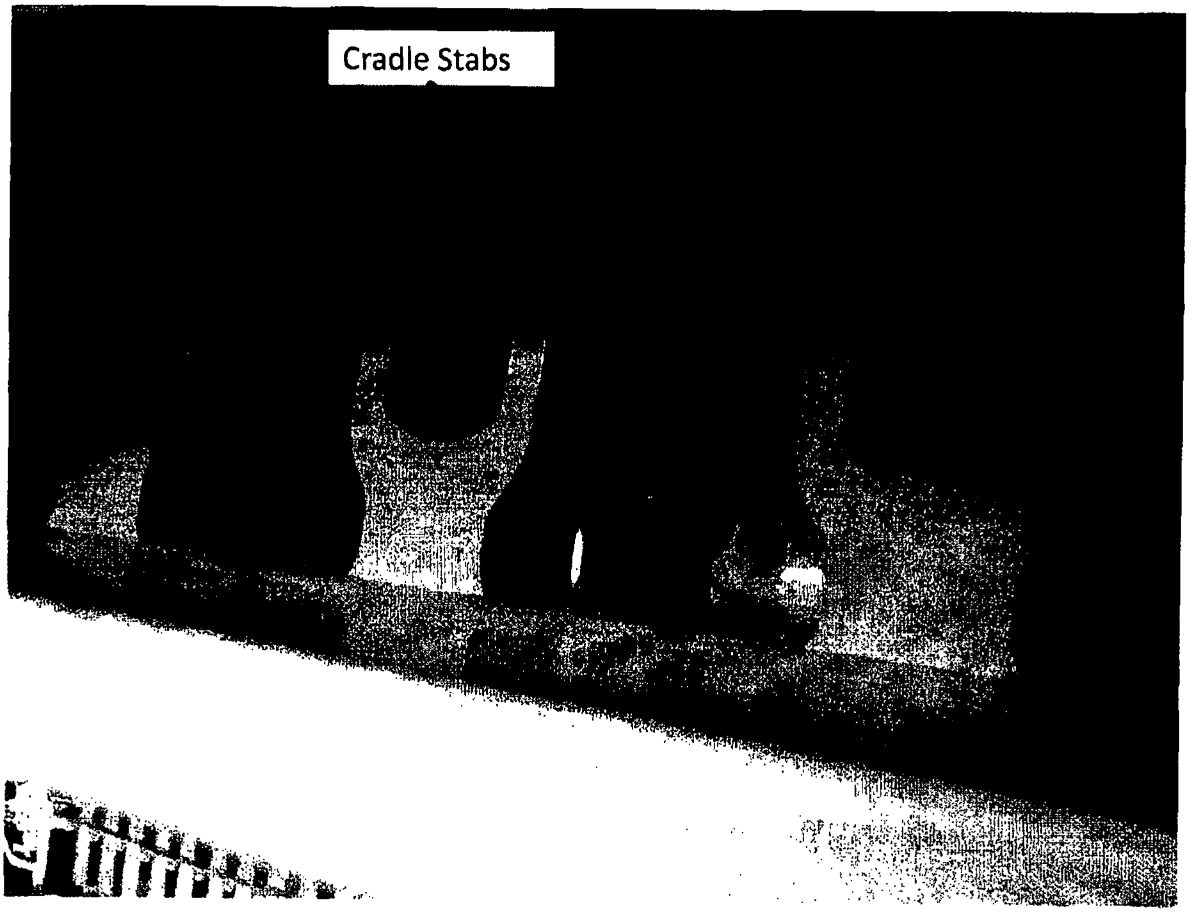


Figure 5: Picture of Cradle Stabs (Internal)

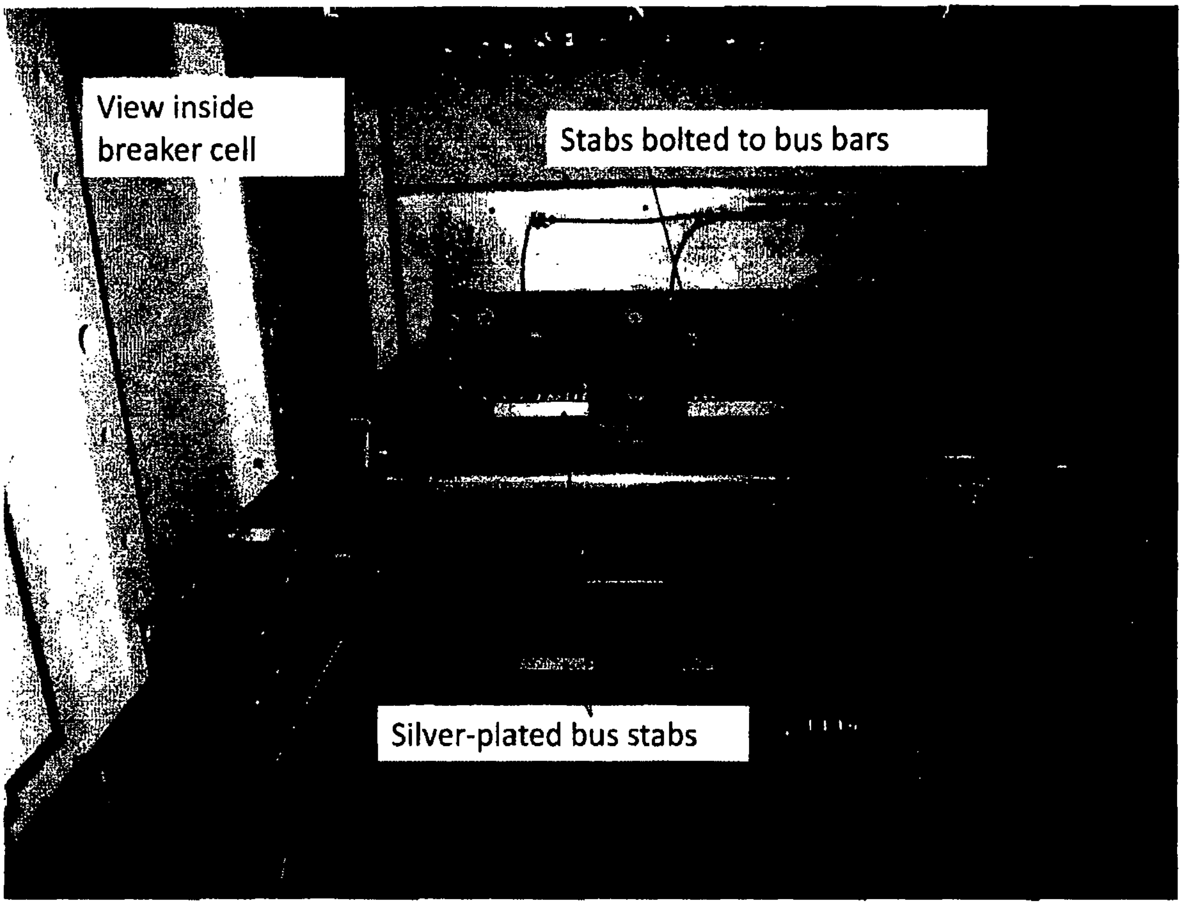


Figure 6: View inside switchgear cell (Before)

Rear bus section showing transition pieces from bus bars to stabs

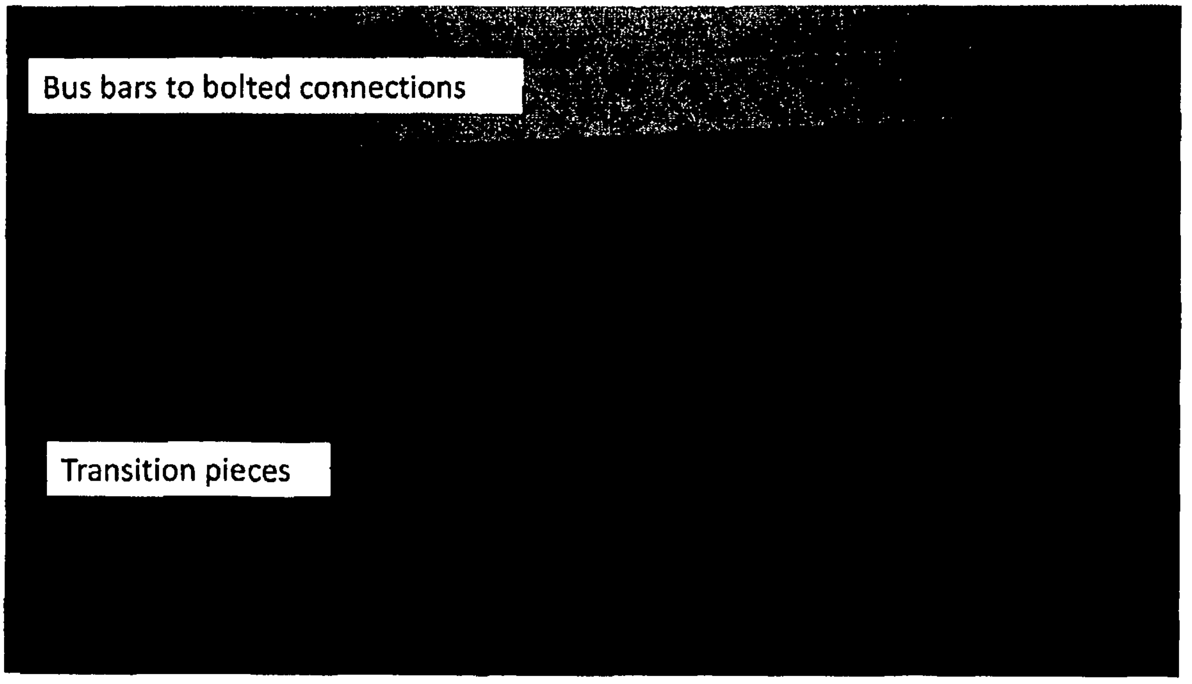


Figure 7: View inside bus compartment

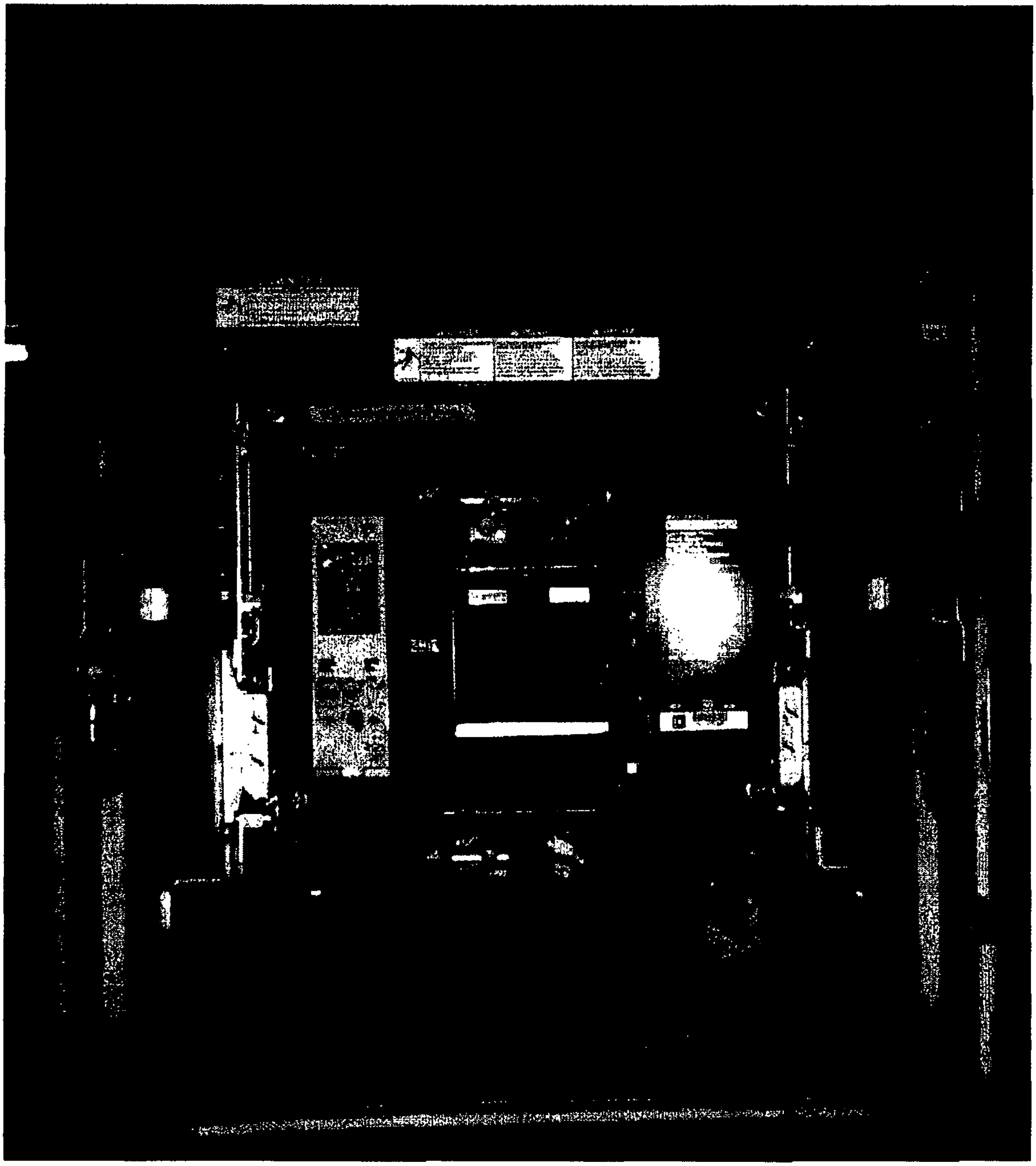


Figure 8: Breaker in Cradle

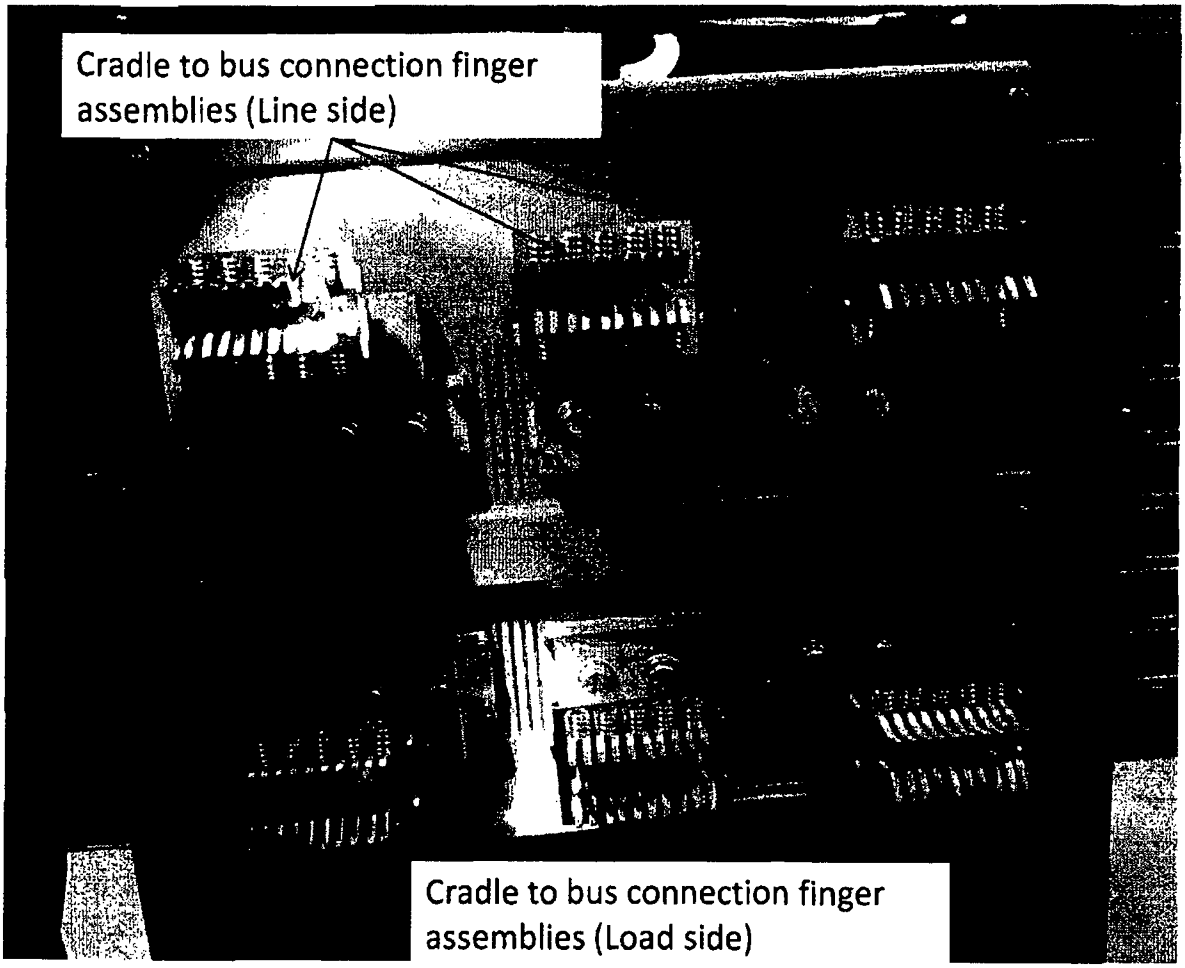


Figure 9: Rear View of Cradle Assembly (Before)

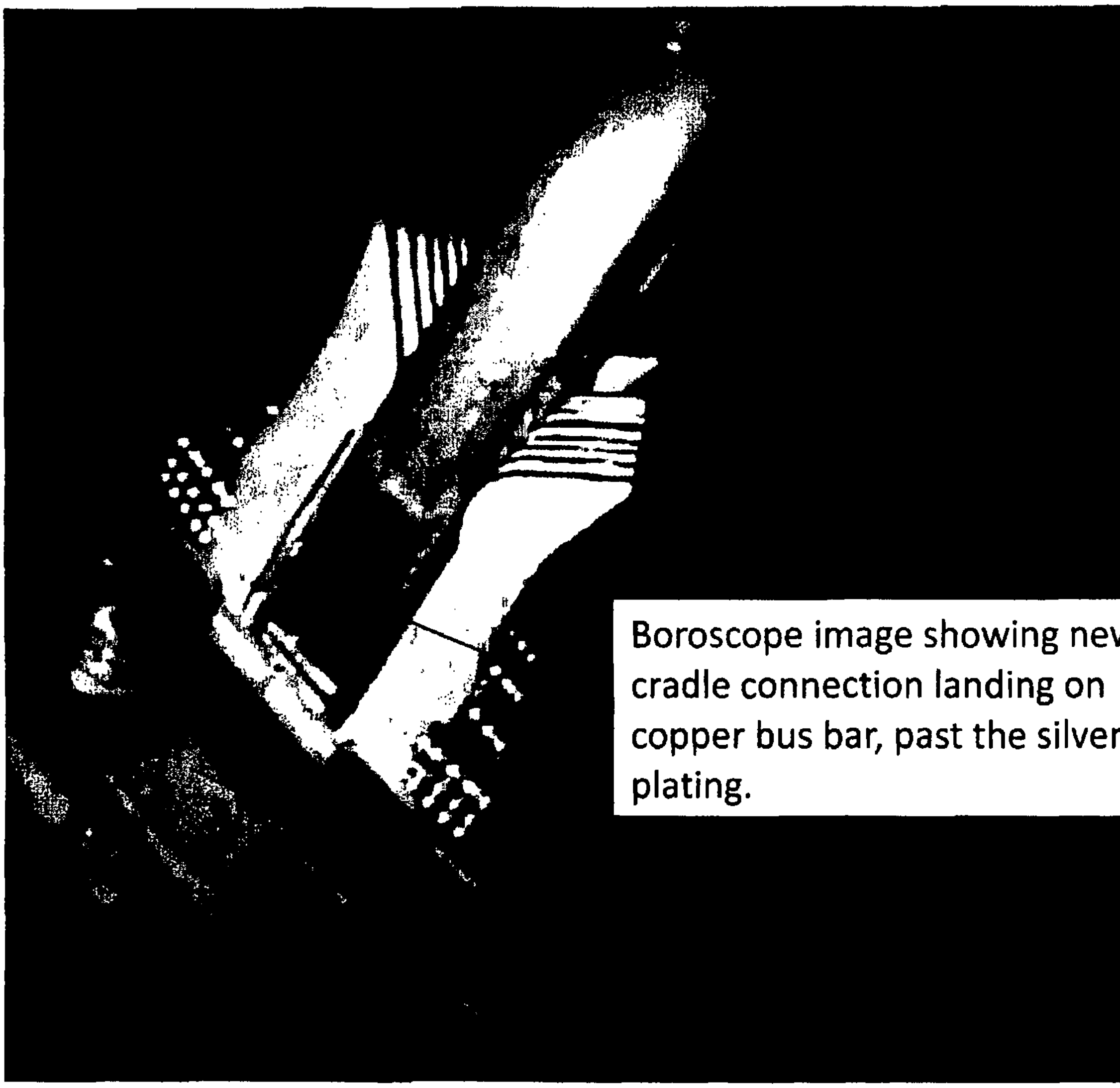


Figure 10: Image of Existing Cradle to Stab Connection

Figure 11: Rear View of Cradle (After)

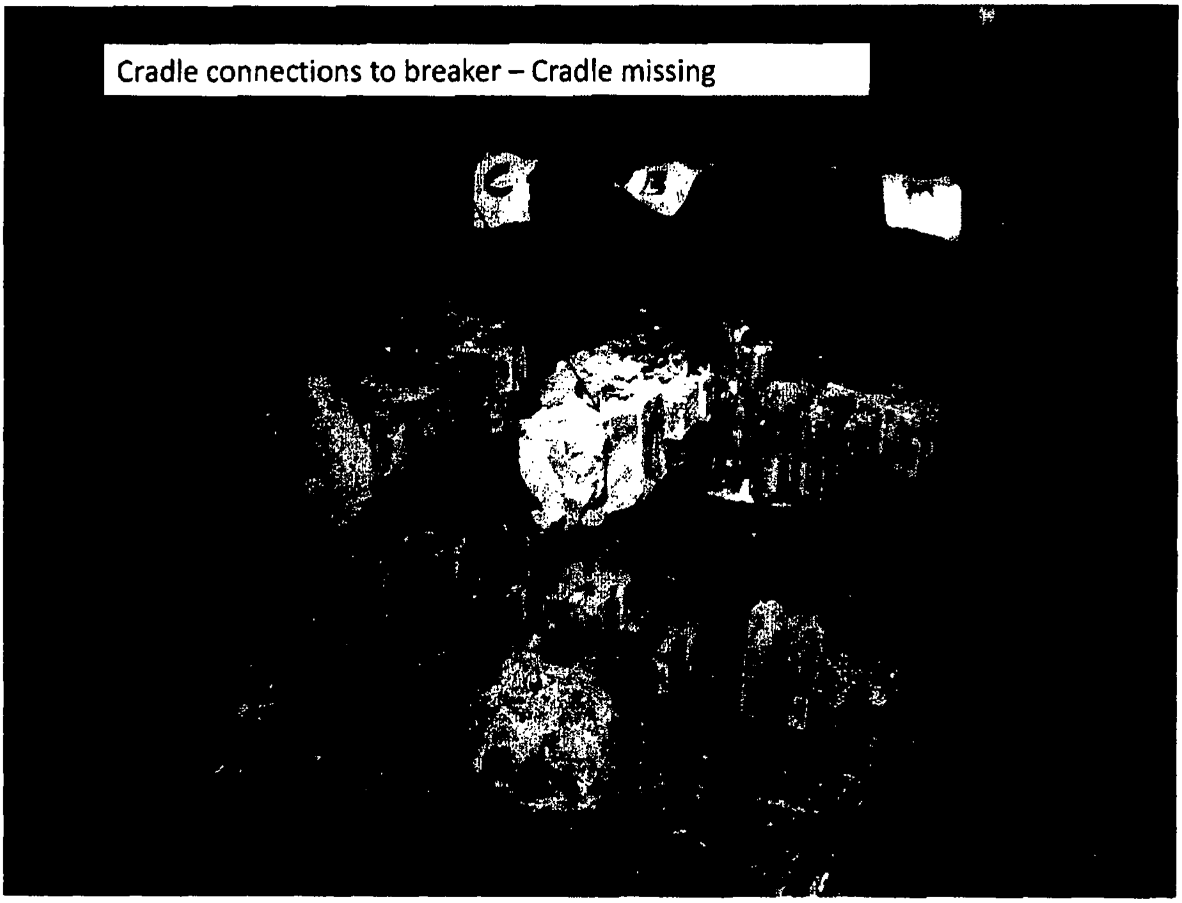


Figure 12: Rear View of Breaker (After)

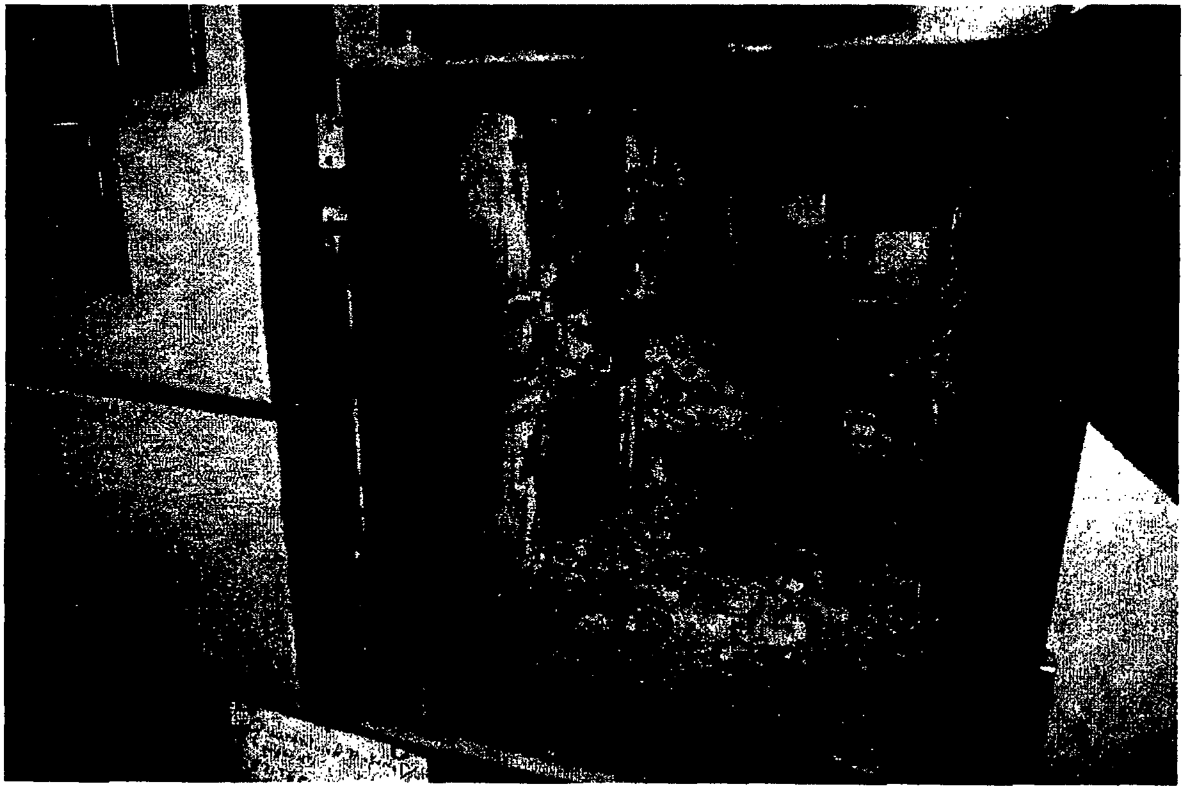


Figure 13: View of Switchgear Cell (After)

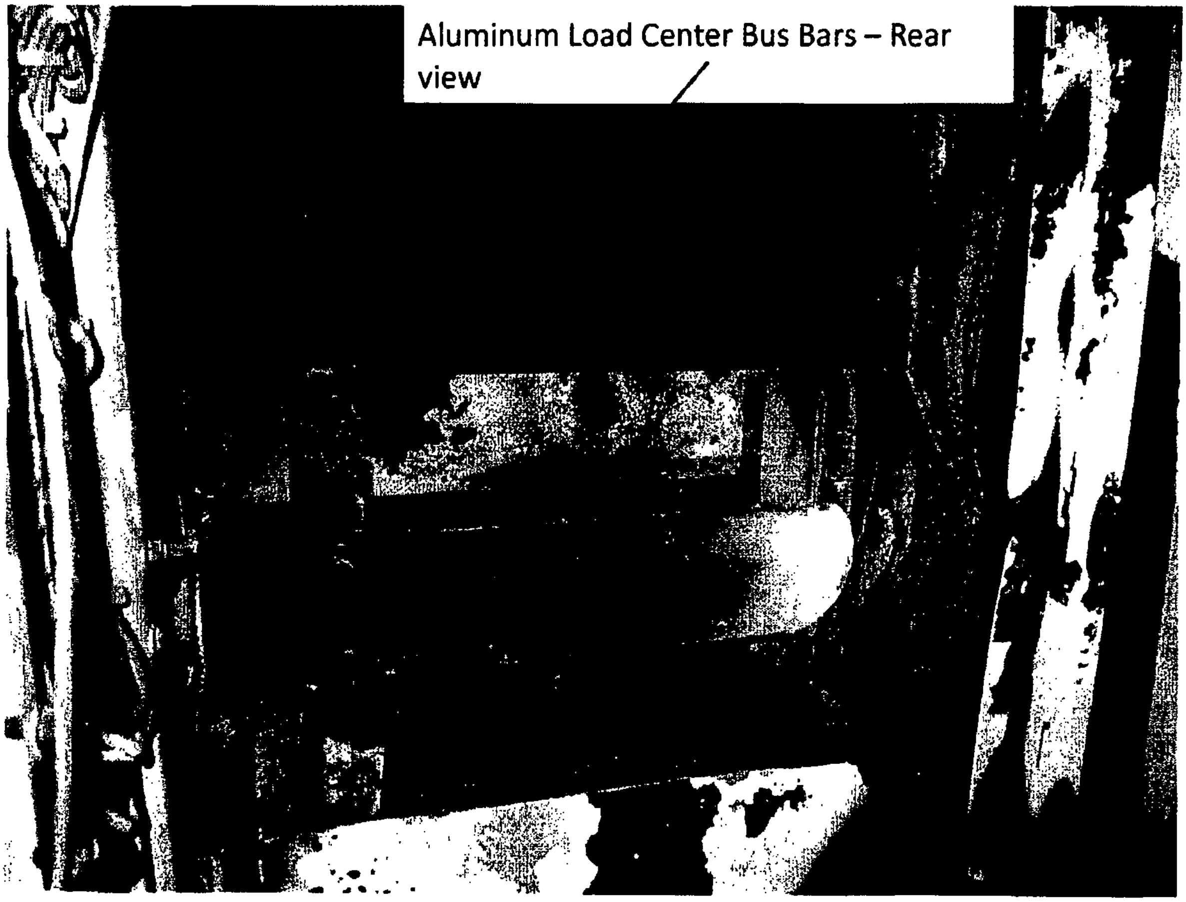


Figure 14: View of Bus Compartment (After)

Figure 15: Bus Compartment. Notice Cradle.

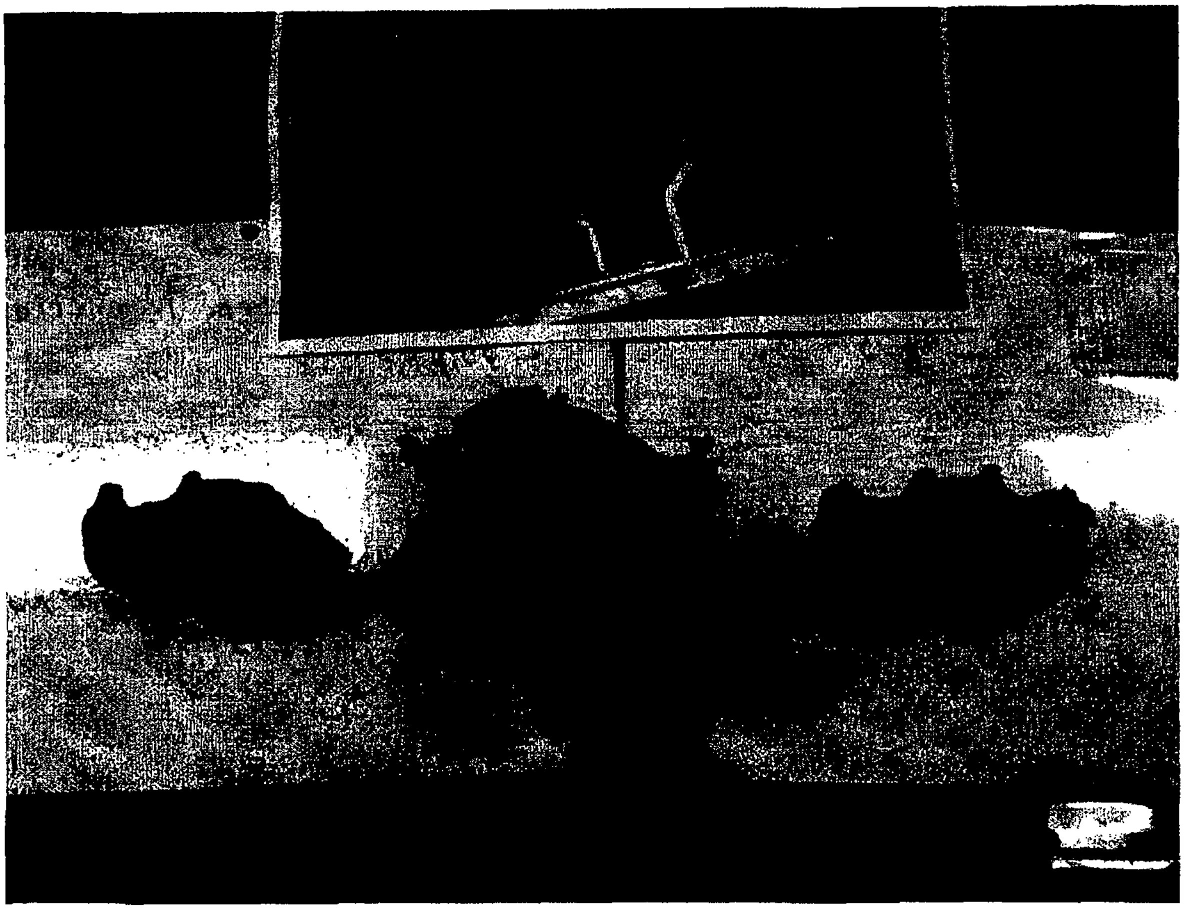


Figure 16: Parts from Bus Compartment

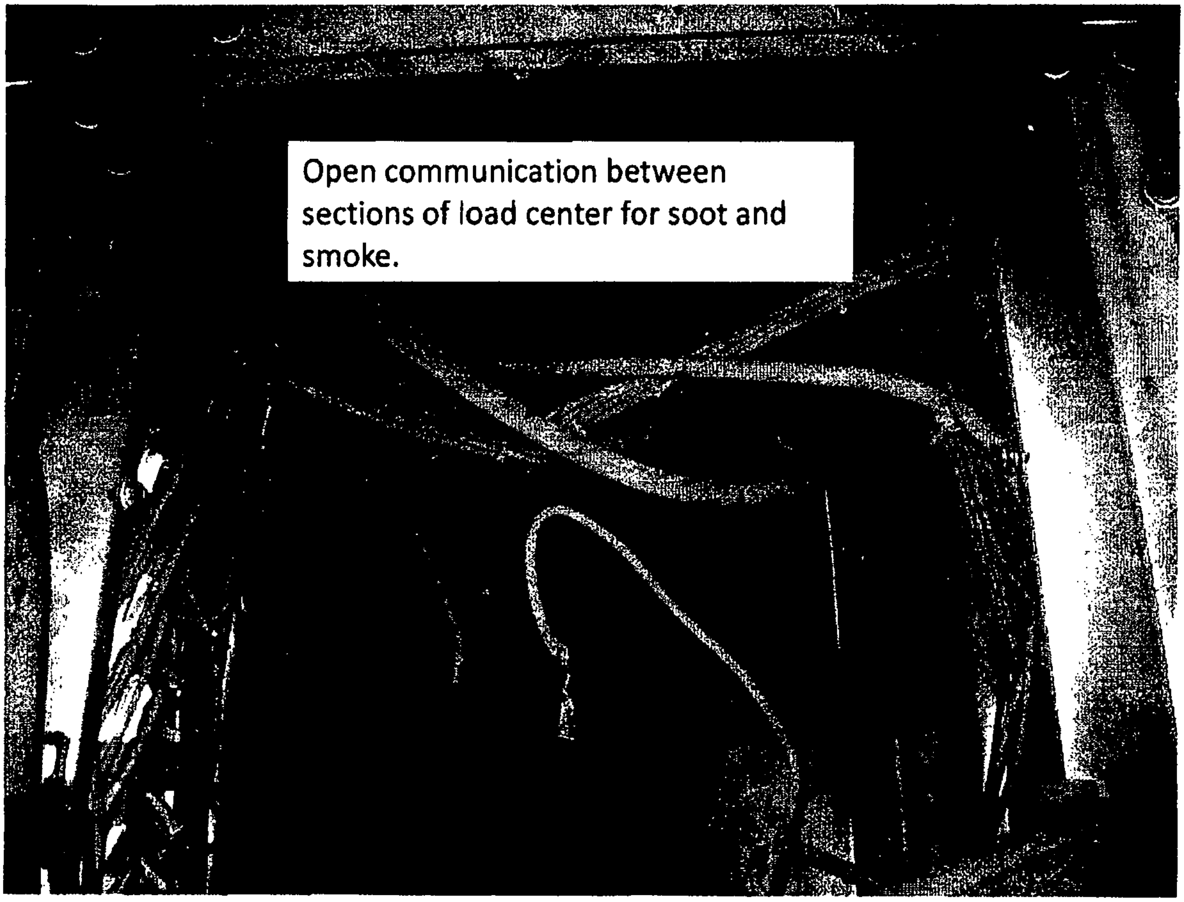


Figure 17: Internal View of Upper Section

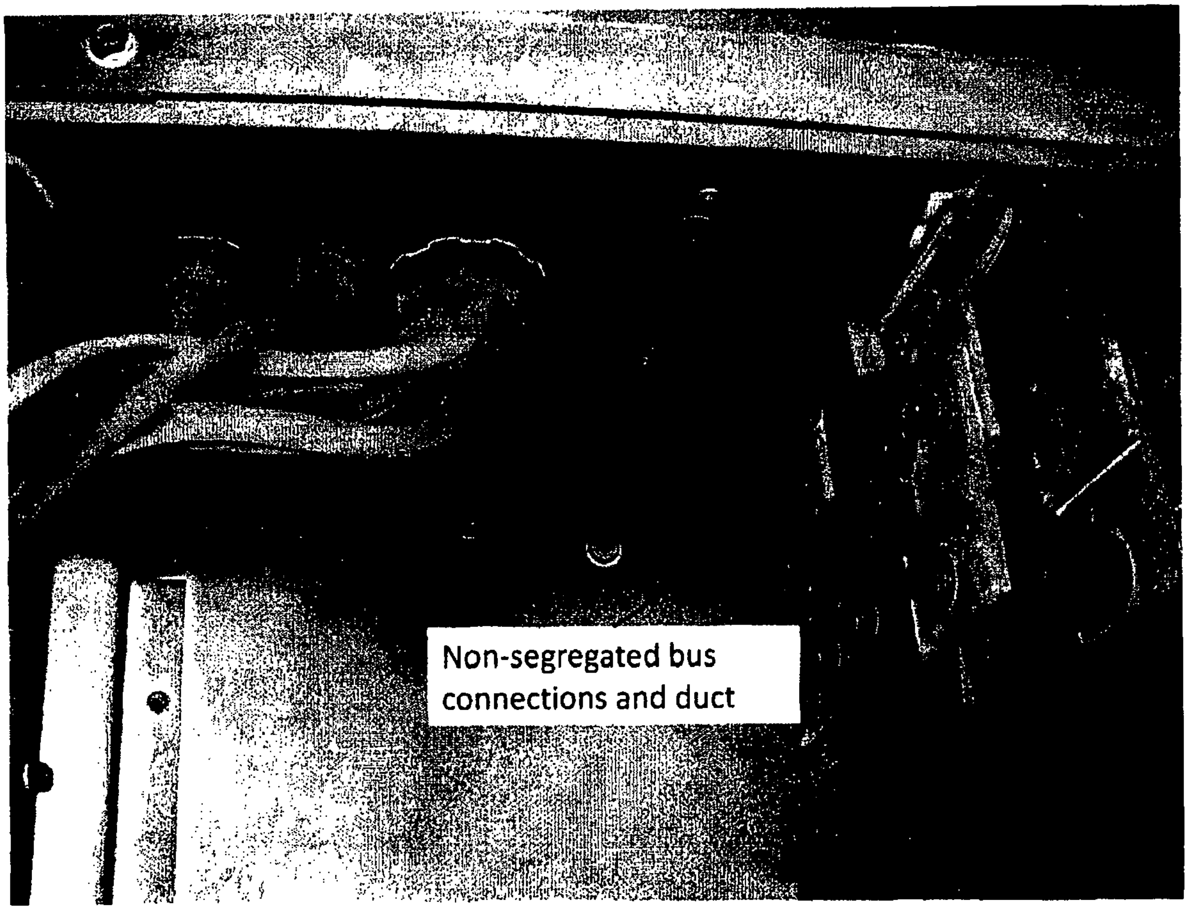


Figure 18: Bus Tie to Island Bus Connections

Release in part

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
1600 EAST LAMAR BLVD
ARLINGTON, TEXAS 76011-4511

April 10, 2012

EA-12-023

David J. Bannister, Vice President
and Chief Nuclear Officer
Omaha Public Power District
Fort Calhoun Station FC-2-4
P O. Box 550
Fort Calhoun, NE 68023-0550

SUBJECT: FINAL SIGNIFICANCE DETERMINATION (b)(5) OF RED FINDING AND NOTICE OF VIOLATION, NRC INSPECTION REPORT 05000285/2012010, FORT CALHOUN STATION

Ex 5

Dear Mr. Bannister:

This letter provides the final significance determination of the preliminary Red finding discussed in our previous communication dated March 12, 2012, which included NRC Inspection Report 05000285/2011014 (b)(5) (ADAMS Accession No. ML12072A128). The finding involved deficient modification and maintenance of the safety-related 480 Vac electrical distribution system and a failure to maintain in effect all provisions of the approved fire protection program.

Ex 5

(b)(5)

In your letter dated March 22, 2012 (ADAMS Accession No. ML12083A036), you indicated that Omaha Public Power District accepted the characterization of the Red finding, and that you declined your opportunity to discuss this issue in a Regulatory Conference or to provide a written response.

After considering the information developed during the inspection, the NRC has concluded that the finding is appropriately characterized as Red, high safety significance (b)(5)

(b)(5)

Ex 5

The NRC has concluded that the failure to ensure that the 480 Vac electrical power distribution system design requirements were properly implemented and maintained through proper maintenance, modification, and design activities along with the failure to implement and maintain in effect all provisions of the fire protection program are violations of NRC requirements, as cited in the attached Notice of Violation (Notice). The circumstances surrounding the violations were described in detail in NRC Inspection Report 05000285/2011014 (b)(5) In accordance with the NRC Enforcement

Ex 5

D7

Policy, the Notice is considered escalated enforcement action because it is associated with a Red finding.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. If you have additional information that you believe the NRC should consider, you may provide it in your response to the Notice. The NRC review of your response to the Notice will also determine whether further enforcement action is necessary to ensure compliance with regulatory requirements.

Fort Calhoun Station is currently shutdown and in the oversight process described by Inspection Manual Chapter 0350, "Oversight of Reactor Facilities in a Shutdown Condition Due to Significant Performance and/or Operational Concerns." Therefore, follow up inspection activities related to this finding will be incorporated as part of the Manual Chapter 0350 inspection process.

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 NRC's document system (ADAMS), accessible from the NRC Web site at http://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,

Elmo E. Collins
Regional Administrator

Docket: 50-285
License: DPR-40

Enclosure:
Notice of Violation

Electronic Distribution for Fort Calhoun

Policy, the Notice is considered escalated enforcement action because it is associated with a Red finding.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. If you have additional information that you believe the NRC should consider, you may provide it in your response to the Notice. The NRC review of your response to the Notice will also determine whether further enforcement action is necessary to ensure compliance with regulatory requirements.

Fort Calhoun Station is currently shutdown and in the oversight process described by Inspection Manual Chapter 0350, "Oversight of Reactor Facilities in a Shutdown Condition Due to Significant Performance and/or Operational Concerns." Therefore, follow up inspection activities related to this finding will be incorporated as part of the Manual Chapter 0350 inspection process.

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 NRC's document system (ADAMS), accessible from the NRC Web site at http://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,

Elmo E. Collins
Regional Administrator

Docket: 50-285
License: DPR-40

Enclosure:
Notice of Violation

Electronic Distribution for Fort Calhoun

Electronic distribution by RIV:
Regional Administrator (Elmo.Collins@nrc.gov)
Deputy Regional Administrator (Art.Howell@nrc.gov
DRP Director (Kriss.Kennedy@nrc.gov)
DRP Deputy Director (Troy.Pruett@nrc.gov)
DRS Director (Anton.Vegel@nrc.gov)
DRS Deputy Director (Tom.Blount@nrc.gov)
Senior Resident Inspector (John.Kirkland@nrc.gov)
Resident Inspector (Jacob.Wingebach@nrc.gov)
Branch Chief, DRP/F (Jeff.Clark@nrc.gov)
Senior Project Engineer, DRP/F (Rick.Deese@nrc.gov)
Project Engineer, DRP/F (Chris.Smith@nrc.gov)
FCS Administrative Assistant (Berni.Madison@nrc.gov)
Public Affairs Officer (Victor.Dricks@nrc.gov)
Public Affairs Officer (Lara.Uselding@nrc.gov)
Acting Branch Chief, DRS/TSB (Ryan.Alexander@nrc.gov)
Project Manager (Lynnea.Wilkins@nrc.gov)
RITS Coordinator (Marisa.Herrera@nrc.gov)
Regional Counsel (Karla.Fuller@nrc.gov)
Congressional Affairs Officer (Jenny.Weil@nrc.gov)
OEMail Resource

Inspection Reports/MidCycle and EOC Letters to the following:
ROPreports

Only inspection reports to the following:
RIV/ETA: OEDO (Lydia.Chang@nrc.gov)
DRS/TSB STA (Dale.Powers@nrc.gov)

R:\REACTORS\FCS\FCS 2012010-NOV ADAMS ML

ADAMS: □ No X Yes	X SUNSI Review Complete	Reviewer Initials: STG
Category B.1	X Publicly Available	X Non-Sensitive
Category A.	□ Non-publicly Available	□ Sensitive
KEYWORD:		

SRI:DRS/EB2	C:DRS/EB2	SRA:DRS	C:DRP/F	[illegible]
SGraves	GMiller	DLoveless	JClark	TPruett
	/RA/	/RA/	/RA/	
	3/27/12	3/27/12	3/28/12	
D:DRS	RIV/ACES	OE	Regional Counsel	DRA
AVegel	HGepford	GGulla	KFuller	AHowell
RA				
ECollins				

NOTICE OF VIOLATION

Omaha Public Power District
Fort Calhoun Station

Docket No.: 50-285
License No.: DPR-40
EA-12-023

During an NRC inspection conducted from September 12, 2011, to February 29, 2012, violations of NRC requirements were identified. In accordance with the NRC Enforcement Policy, the violations are listed below:

A. Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part that: (1) design changes, including field changes, be subject to design control measures commensurate with those applied to the original design; (2) measures be established to assure that applicable regulatory requirements and the design basis for safety-related structures, systems, and components are correctly translated into specifications, drawings, procedures, and instructions; and (3) these measures assure that appropriate quality standards are specified and included in design documents and that deviations from such standards are controlled.

Contrary to the above requirement, from November 2009 to June 7, 2011, the licensee failed to ensure that design changes were subject to design control measures commensurate with those applied to the original design; failed to assure that applicable regulatory requirements and the design basis for (b)(5) safety-related structures, systems, and components were correctly translated into drawings, procedures, and instructions; and failed to ensure that these measures assured that appropriate quality standards were specified and included in the design documents. Specifically, design reviews, work planning and instructions for a modification to install new 480 Vac load center breakers failed to ensure that the cradle adapter assemblies had low resistance connections with the switchgear bus bars by establishing a proper fit and requiring low resistance connections to assure that design basis requirements were maintained.

Ex 5

B. Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures be established to assure that conditions adverse to quality such as failures, defective material and equipment, and nonconformances are promptly identified and corrected. (b) In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.

Ex 5

Ex 5

Contrary to the above requirement, from May 22, 2008, to June 7, 2011, the licensee failed to assure that (b)(5) to quality (b)(5) corrective actions were (b)(5) (b)(5) taken to preclude repetition. Specifically, the licensee failed to ensure that their preventative maintenance program for the safety-related 480 Vac electrical power distribution system was adequate to ensure proper cleaning of conductors, proper torquing of bolted conductor or bus bar connections, and adequate inspection for abnormal connection temperatures. In 2008, the licensee identified that preventative

(b)(5)

D8

NOTICE OF VIOLATION

Omaha Public Power District
Fort Calhoun Station

Docket No.: 50-285
License No.: DPR-40
EA-12-023

During an NRC inspection conducted from September 12, 2011, to February 29, 2012, violations of NRC requirements were identified. In accordance with the NRC Enforcement Policy, the violations are listed below:

A. Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part that: (1) design changes, including field changes, be subject to design control measures commensurate with those applied to the original design; (2) measures be established to assure that applicable regulatory requirements and the design basis for safety-related structures, systems, and components are correctly translated into specifications, drawings, procedures, and instructions; and (3) these measures assure that appropriate quality standards are specified and included in design documents and that deviations from such standards are controlled.

Contrary to the above requirement, from November 2009 to June 7, 2011, the licensee failed to ensure that design changes were subject to design control measures commensurate with those applied to the original design; failed to assure that applicable regulatory requirements and the design basis for (b)(5) safety-related structures, systems, and components were correctly translated into drawings, procedures, and instructions; and failed to ensure that these measures assured that appropriate quality standards were specified and included in the design documents. Specifically, design reviews, work planning and instructions for a modification to install new 480 Vac load center breakers failed to ensure that the cradle adapter assemblies had low resistance connections with the switchgear bus bars by establishing a proper fit and requiring low resistance connections to assure that design basis requirements were maintained.

EX 5

B. Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures be established to assure that conditions adverse to quality such as failures, defective material and equipment, and nonconformances are promptly identified and corrected. (b) n the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.

EX 5

EX 5

Contrary to the above requirement, from May 22, 2008, to June 7, 2011, the licensee failed to assure that (b)(5) to quality (b)(5) corrective actions were (b)(5) (b)(5) taken to preclude repetition. Specifically, the licensee failed to ensure that their preventative maintenance program for the safety-related 480 Vac electrical power distribution system was adequate to ensure proper cleaning of conductors, proper torquing of bolted conductor or bus bar connections, and adequate inspection for abnormal connection temperatures. In 2008, the licensee identified that preventative

(b)(5)

maintenance procedure EM-PM-EX-1200, "Inspection and Maintenance of Model AKD-5 Low Voltage Switchgear," was less than adequate as a result of a root cause analysis for the failure of bus-tie breaker BT-1B3A to close on demand and loss of bus 1B3A. The licensee categorized this failure as a significant condition adverse to quality. The analysis concluded that breaker BT-1B3A had high resistance connections which occurred as a result of both procedure deficiencies and inadequate implementation resulting in the failure to remove dirt and hardened grease from electrical connections. The licensee implemented corrective actions to address these procedural deficiencies; however the corrective actions were inadequate to prevent high resistance connections in load center 1B4A due to the presence of hardened grease and oxidation. The procedure did not contain adequate guidance for torquing bolted connections or measuring abnormal connection temperatures due to loose electrical connections in the bus compartment of the switchgear.

C. License Condition 3.D, "Fire Protection Program," requires, in part, that the licensee implement and maintain in effect all provisions of the approved Fire Protection Program as described in the Updated Safety Analysis Report and as approved in NRC safety evaluation reports. Section 9.11.1 of the Updated Safety Analysis Report describes the fire protection system design basis and states, in part, that the design basis of the fire protection systems includes commitments to 10 CFR Part 50, Appendix R, Section III.G. (b)(5) [redacted] "Fire protection of safe shutdown capability," requires, in part, that fire protection features be provided for structures, systems, and components important to safe shutdown, and that these features be capable of limiting fire damage so that one train of systems necessary to achieve and maintain hot shutdown conditions is free of fire damage. Ex 5

Contrary to the above requirement, from November, 2009, to June 7, 2011, the licensee failed to implement and maintain in effect all provisions of the approved Fire Protection Program. Specifically, the licensee failed to ensure that design reviews for electrical protection and train separation of the 480 Vac electrical power distribution system were adequate to ensure that a fire in load center 1B4A would not adversely affect operation of redundant safe shutdown equipment in load center 1B3A, such that one train of systems necessary to achieve and maintain hot shutdown conditions were free of fire damage. Combustion products from the fire in load center 1B4A migrated across normally open bus-tie breaker BT-1B4A into the non-segregated bus duct, shorting all three electrical phases. The non-segregated bus ducting electrically connected load center 1B4A with the Island Bus 1B3A-4A and, through normally closed bus-tie breaker BT-1B3A, to the redundant safe shutdown train.

These violations are associated with a Red Significance Determination Process finding.

Pursuant to the provisions of 10 CFR 2.201 Omaha Public Power District is hereby required to submit a written statement or explanation 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 (b)(5) [redacted] within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation; EA-12-023" Ex 5

and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

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

Because 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 Web site at http://www.nrc.gov/reading-rm/adams.html, to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you <u>must</u> specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

Dated this 10th day of April 2012.

and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

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

Because 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 Web site at http://www.nrc.gov/reading-rm/adams.html, to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

Dated this 10th day of April 2012.

Release in part (see 2nd page)

Howell, Art

From: Werner, Greg
Sent: Thursday, November 15, 2012 11:10 AM
To: Dricks, Victor
Cc: Bloodgood, Michael; Lantz, Ryan; Taylor, Nick; Howell, Art
Subject: RE: Has SCE identified the ROOT CAUSE of SanO Failure?

I recommend a phone call vs. an e-mail message. As part of the CAL inspection, we will be reviewing the causes of the tube-to-tube wear and making a determination as to the adequacy of the proposed corrective actions.

From: Taylor, Nick
Sent: Thursday, November 15, 2012 10:48 AM
To: Werner, Greg
Cc: Bloodgood, Michael; Dricks, Victor
Subject: FW: Has SCE identified the ROOT CAUSE of SanO Failure?

Greg,

See question from Victor (from a member of the public) below. I didn't want to guess...what has SCE said? Can you take a shot at a response?

Thanks,
Nick

From: Dricks, Victor
Sent: Thursday, November 15, 2012 9:14 AM
To: Taylor, Nick
Subject: FW: Has SCE identified the ROOT CAUSE of SanO Failure?

Could you draft a response for me so I can respond to this e-mail?

During the September 12, 2012 Senate hearing on San Onofre NRC Chair Macfarlane testified that the NRC would not allow Edison to restart San Onofre unless (after receiving a Confirmatory Action Letter from Edison) the NRC "understand[s] whether [Edison has] understood well enough the **root causes** of the problem."

It's my understanding that Edison has named fluid-elastic instability as one of several mechanical causes for the San Onofre failures - but as yet has not provided the NRC with a written ROOT CAUSE ANALYSIS.

Questions:

1) Has the NRC required Edison to provide a written ROOT CAUSE ANALYSIS of the San Onofre Steam Generator Failures? In accordance with the NRC Confirmatory Action Letter to SCE dated March 27, 2012, SCE is required to determine the causes of the tube-to-tube wear and implement actions to prevent loss of tube integrity due to these causes in Unit 2. In accordance with 10 CFR Part

D9

50 Appendix B, Criterion XVI, for significant conditions adverse to quality (which loss of tube integrity is), SCE is required to document the cause(s) for the tube failures and corrective actions to prevent it from occurring again.

2) Has Edison provided a written ROOT CAUSE ANALYSIS of the San Onofre Steam Generator Failures to the NRC? SCE has provided a root cause analysis for the tube failures as discussed during the June 18, 2012 AIT public exit meeting. In addition, Mitsubishi Heavy Industries also completed a root cause analysis which the NRC has reviewed.

I look forward to having these questions answered.

Sincerely,

(b)(6) Ex 6

2

Johnson, Andrew

From: Werner, Greg RIV
Sent: Saturday, March 24, 2012 3:08 PM
To: Rivera-Ortiz, Joel; Johnson, Andrew; Ortega-Luciano, Jonathan; Murphy, Emmett; Thurston, Carl; Reynoso, John
Cc: Werner, Greg
Subject: Unresolved Items - Action and Response Requested
Attachments: SONGS AIT Unresolved Item List.docx

Importance: High

See the attached file for a list of what I think I've heard are the current unresolved items. If I missed something, let me know ASAP. If after reading the information below and you think you might have an unresolved item, let's discuss. If we are not sure, I will put it on the list as PENDING.

What is an unresolved item? See below:

From MC 0612, "Power Reactor Inspection Reports"

03.47 Unresolved Item (URI). An issue of concern about which more information is required to determine (a) if a performance deficiency exists, (b) if the performance deficiency is more than minor, or (c) if the issue of concern constitutes a violation. Such a matter may require additional information from the licensee or cannot be resolved without additional guidance, clarification, or interpretation of the existing guidance.

Now you are probably wondering what an "issue of concern" is:

03.20 Issue of Concern (IOC). A well-defined observation or collection of observations that is of concern and may or may not involve a performance deficiency.

Normally, unresolved items are at a high threshold. In Region IV, we do NOT routinely issue unresolved items. So, we are going to be very liberal (Not in a political sense!). Basically, if you are reviewing items and you review something that does not appear to be right and documents that you review show that procedures or ASME or ANSI guidance was not followed, then you should consider making that an unresolved item. During a normal inspection, you would try and run the issue into the ground and make a determination before leaving site. We do NOT have the time for that. A followup inspection will complete the in-depth review -> We are gathering facts and information, not dispositioning issues.

In this case MORE is BETTER!

D10

Exemption 5

Unresolved Items

Inspector	Charter Item	Issue
(b)(5)		

Release

3

Johnson, Andrew

From: Werner, Greg
Sent: Monday, March 26, 2012 6:44 PM
To: Vegel, Anton; Blount, Tom; Kennedy, Kriss; Pruett, Troy; Lantz, Ryan
Cc: Kulesa, Gloria; Vias, Steven; Hoxie, Chris; Roach, Edward; Johnson, Andrew; Rivera-Ortiz, Joel; Ortega-Luciano, Jonathan; Murphy, Emmett; Reynoso, John; Thurston, Carl
Subject: AIT Regional Debrief for Monday, March 26
Attachments: SONGS AIT Daily RIV Debrief Notes.docx; SONGS AIT Unresolved Item List.docx

Here are the notes for our debrief today as well as a proposed list of URIs.

Greg Werner

D11

Daily Debrief Notes
with
Region IV

Brief Summary of Charter Items

(b)(5)

Monday, March 26

(b)(5)

(b)(5)

Friday, March 23

(b)(5)

(b)(5)

Thursday, March 22

(b)(5)

(b)(5)

Wednesday, March 21

(b)(5)

(b)(5)

Unresolved Items

Inspector	Charter Item	Issue

(b)(5)

4

Johnson, Andrew

From: Werner, Greg
Sent: Tuesday, March 27, 2012 6:39 PM
To: Blount, Tom; Vegel, Anton; Kennedy, Kriss; Pruett, Troy; Lantz, Ryan
Cc: Kulesa, Gloria; Vias, Steven; Hoxie, Chris; Roach, Edward; Calle, Joselito; Rivera-Ortiz, Joel; Ortega-Luciano, Jonathan; Johnson, Andrew; Murphy, Emmett; Thurston, Carl; Reynoso, John
Subject: SONGS AIT Daily RIV Debrief Notes.docx
Attachments: SONGS AIT Unresolved Item List.docx; SONGS AIT Daily RIV Debrief Notes.docx

FYI

D/2

Unresolved Items

Inspector	Charter Item	Issue
(b)(5)		

(b)(5)

Daily Debrief Notes
with
Region IV

Brief Summary of Charter Items

(b)(5)

Tuesday, March 27

(b)(5)

Monday, March 26

(b)(5)

(b)(5)

Friday, March 23

(b)(5)

(b)(5)

Thursday, March 22

(b)(5)

(b)(5)

Wednesday, March 21

(b)(5)

(b)(5)

S

Johnson, Andrew

From:	Werner, Greg
Sent:	Wednesday, March 28, 2012 4:32 PM
To:	Blount, Tom; Vegel, Anton; Kennedy, Kriss; Pruett, Troy; Lantz, Ryan
Cc:	Warnick, Greg; Reynoso, John; Ortega-Luciano, Jonathan; Rivera-Ortiz, Joel; Murphy, Emmett; Johnson, Andrew; Thurston, Carl; Kulesa, Gloria; Roach, Edward; Vias, Steven; Hoxie, Chris
Subject:	SONGS AIT Unresolved Item List
Attachments:	SONGS AIT Unresolved Item List.docx

Forgot to include this with my previous e-mail.

I did have another discussion with Jonathan Ortega-Luciano (Vendor Branch) about the need to go to Japan to look at MHI and their subcontractors. He did have a conversation with Ed Roach, and Ed is going to meet with his management to discuss their recommendation. Based on what Jonathan and I have discussed, we don't have any technical reason to go to Japan. There were some QA issues initially, but MHI aggressively corrected them and SONGS provided very good oversight. Jonathan is finishing his review of MHI's QA oversight of their subcontractors (such as Sumitomo) and if he finds anything of concern, we will share them with management -> right now it looks like MHI provided good oversight of their subs.

Greg Werner

D3

Unresolved Items

Inspector	Charter Item	Issue
(b)(5)		

(b)(5)

6

Johnson, Andrew

From: Werner, Greg
Sent: Wednesday, March 28, 2012 9:55 AM
To: Murphy, Emmett; Rivera-Ortiz, Joel; Ortega-Luciano, Jonathan; Johnson, Andrew; Reynoso, John; Thurston, Carl
Cc: johnsonab@gmail.com
Subject: Debrief Notes - Response Required ASAP
Attachments: SONGS AIT Debrief 3_29_12.docx

Importance: High

Good Morning All,

Just finished up the first draft of debrief notes for tomorrow afternoon, see attached file. I need you to review and comment on them. In particular, the text in the Yellow highlighted sections that is red font and bolded -> I need to get input from you. I do want everyone to read the entire debrief and make sure I didn't say anything technically incorrect or wrong. Please pay particular attention to Item 2 and my overall summary statement after Item 12.

If you could please review and comment before noon, that would allow me to make changes and discuss with you before the end of the day today.

Thanks,
Greg Werner

D14

(b)(5)

(b)(5)

(b)(5)

(b)(5)

(b)(5)

2. (b)(5)

(b)(5)

3.

(b)(5)

4.

(b)(5)

(b)(5)

5.

(b)(5)

(b)(5)

6.

(b)(5)

7.

(b)(5)

(b)(5)

8.

(b)(5)

(b)(5)

9. (b)(5)

(b)(5)

10.

(b)(5)

11.

(b)(5)

12.

(b)(5)

(b)(5)

Craver, Patti 7

From:	Morrison, Catherine
Sent:	Wednesday, May 02, 2012 1:46 PM
To:	Zeiler, John; McCree, Victor; Wert, Leonard; Dodson, Jim; Croteau, Rick; Borchardt, Bill; Virgilio - Disabled 5-4-2012 per 574504, Martin; Jones, William; Lessard, Patrick; Patterson, Robert; Worosilo, Jannette; Billoch, Araceli; Farnan, Michael
Cc:	Musser, Randy
Subject:	Special Inspection Charter to Evaluate the Failure of Two Main Steam Isolation Valves to Close at Harris
Attachments:	Harris SI charter 042612 (3).docx

Please find the above referenced charter attached.

ML12123A202

U.S. Nuclear Regulatory Commission
Division of Reactor Projects
245 Peachtree Center Avenue, NE, Suite 1200
Atlanta, Georgia 30303-1257
404-997-4559
Fax: 404-997-4905

Catherine Morrison
Administrative Assistant,
Branches 3, 4, 5 & 7

Catherine.Morrison@NRC.gov

D15

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE NE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

May 2, 2012

MEMORANDUM TO: John Zeiler
Senior Resident Inspector, McGuire
Division of Reactor Projects

FROM: Victor M. McCree ***/RA by Leonard Wert Acting For/***
Regional Administrator

SUBJECT: SPECIAL INSPECTION CHARTER TO EVALUATE THE FAILURE OF TWO MAIN STEAM ISOLATION VALVES TO CLOSE AT HARRIS

You have been selected to lead a Special Inspection to assess the circumstances surrounding the failure of the 'B' and 'C' Main Steam Isolation Valves (MSIVs) to close from the main control board on April 21, 2012, and the delayed closure of the MSIVs after the instrument air supply was isolated at Harris Nuclear Plant (HNP). Your onsite inspection should begin on May 7, 2012. Patrick Lessard, Mike Farnan and Robert Patterson will be assisting you in this inspection.

A. Basis

At approximately 0500 EDT on April 21, 2012, the Harris Nuclear Plant was at 0% power in Mode 4 and in the process of a normal plant shutdown for a refueling outage. During the performance of procedure OST-1046, MSIV Operability Test, 'B' and 'C' Main Steam Isolation Valves (MSIV) failed to close from the main control board. The 'B' MSIV shut 37 minutes after the instrument air supply was isolated to the valve. The 'C' MSIV shut about 3 hours after the instrument air was isolated. This event was reported to the NRC as Event Notification EN 47857 dated April 21, and updated on April 24.

In accordance with Management Directive (MD) 8.3, "NRC Incident Investigation Program," deterministic and conditional risk criteria were used to evaluate the level of NRC response for this operational event. Through review of the MD 8.3 deterministic criteria, the staff concluded that this event resulted in a significant loss of integrity of the primary containment boundary, a loss of safety function, and could possibly involve adverse generic implications. The staff noted this event may also involve a repetitive failure in that a similar event occurred with the 'B' MSIV on November 15, 2009. The conditional core damage probability (CCDP) for this event met the criterion for a Special Inspection. Region II determined that the appropriate level of NRC response is a Special Inspection.

CONTACT: Randall Musser, RII/DRP
404-997-4603

This Special Inspection is chartered to identify the circumstances surrounding the failure of the 'B' and 'C' MSIVs to close from the main control board, review the licensee's actions following discovery of the conditions, the condition of the 'A' MSIV and the licensee's actions to address the November 2009 MSIV failure to close.

B. Scope

The inspection is expected to perform data gathering and fact-finding in order to address the following:

1. Develop a sequence of events, including operator actions in response to the slow closure of the 'B' and 'C' MSIVs.

2. Review and assess the use of applicable operating procedures during the event and the applicable ERFIS computer data.

3. Assess the available information on the main control board MSIV switches and the maintenance/repair history.

4. Review work order history and related information for the MSIVs and associated equipment to identify other potential vulnerabilities or maintenance practices which could have contributed to this condition.

5. Assess and review the licensee's troubleshooting related to the 'B' MSIV and 'C' MSIVs.

6. Review the licensee's corrective actions (CAs), causal analysis and extent of condition associated with the MSIV failure to close issue. Considerations should include:
   - Operational decision making
   - Operational experience (internal and external)
   - Vendor information on expected service life, recommended preventative maintenance, and if any bulletins or addendums were issued on similar valves or air actuators.
   - November 2009 'B' MSIV failure to close
   - Condition of the 'A' MSIV

7. Collect data necessary to support completion of the significance determination process, if applicable.

8. Identify any potential generic safety issues and make recommendations for appropriate follow-up action (e.g., Information Notices, Generic Letters, and Bulletins).

C. Guidance

Inspection Procedure 93812, "Special Inspection," provides additional guidance to be used during the conduct of the Special Inspection. Your duties will be as described in Inspection Procedure 93812. The inspection should emphasize fact-finding in its review of the circumstances surrounding the event. Safety or security concerns identified that are not directly related to the event should be reported to the Region II office for appropriate action.

You will report to the site, conduct an entrance, and begin inspection no later than May 7, 2012. A daily status briefing of Region II management will be provided beginning the second day on-site at approximately 4:00 p.m. In accordance with IP 93812, you should promptly recommend a change in inspection scope or escalation if information indicates that the assumptions utilized in the MD 8.3 risk analysis were not accurate. A report documenting the results of the inspection should be issued within 45 days of the completion of the inspection. The report should address all applicable areas specified in section 3.02 of Inspection Procedure 93812. At the completion of the inspection you should provide recommendations for improving the Reactor Oversight Process baseline inspection procedures and the Special Inspection process based on any lessons learned.

This Charter may be modified should you develop significant new information that warrants review. Should you have any questions concerning this Charter, contact Randall Musser at 404-997-4603 or Jim Dodson at 404-997-4655.

Docket No. 50-400
License No. NPF-63

cc: R. W. Borchardt, EDO
M. Virgilio, DEDR
V. McCree, RII
L. Wert, RII
R. Croteau, RII
W. Jones, RII
A. Billoch, NRR
R. Musser, RII
J. Dodson, RII
P. Lessard, RII
R. Patterson, RII
M. Farnan, NRR
J. Worosilo, RII

C. Guidance

Inspection Procedure 93812, "Special Inspection," provides additional guidance to be used during the conduct of the Special Inspection. Your duties will be as described in Inspection Procedure 93812. The inspection should emphasize fact-finding in its review of the circumstances surrounding the event. Safety or security concerns identified that are not directly related to the event should be reported to the Region II office for appropriate action.

You will report to the site, conduct an entrance, and begin inspection no later than May 7, 2012. A daily status briefing of Region II management will be provided beginning the second day on-site at approximately 4:00 p.m. In accordance with IP 93812, you should promptly recommend a change in inspection scope or escalation if information indicates that the assumptions utilized in the MD 8.3 risk analysis were not accurate. A report documenting the results of the inspection should be issued within 45 days of the completion of the inspection. The report should address all applicable areas specified in section 3.02 of Inspection Procedure 93812. At the completion of the inspection you should provide recommendations for improving the Reactor Oversight Process baseline inspection procedures and the Special Inspection process based on any lessons learned.

This Charter may be modified should you develop significant new information that warrants review. Should you have any questions concerning this Charter, contact Randall Musser at 404-997-4603 or Jim Dodson at 404-997-4655.

Docket No. 50-400
License No. NPF-63

cc: R. W. Borchardt, EDO
M. Virgilio, DEDR
V. McCree, RII
L. Wert, RII
R. Croteau, RII
W. Jones, RII
A. Billoch, NRR
R. Musser, RII
J. Dodson, RII
P. Lessard, RII
R. Patterson, RII
M. Farnan, NRR
J. Worosilo, RII

*See Previous Concurrence

☐ PUBLICLY AVAILABLE X NON-PUBLICLY AVAILABLE ☐ SENSITIVE X NON-SENSITIVE

ADAMS: XYes ACCESSION NUMBER: ML12123A202 X SUNSI REVIEW COMPLETE

OFFICE	RII:DRP	RII:DRP	RII:DRP	RII:DRP	RII:DRAO		
SIGNATURE	JSD	JXZ via email	RXM1	RXC2	LXW1		
NAME	JDodson	JZeiler	RMusser	RCroteau	LWert		
DATE	05/1/2012	05/1/2012	04/30/2012	05/1/2012	05/02/2012		
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

OFFICIAL RECORD COPY DOCUMENT NAME: G:\DRPII\RPB4\HARRIS\CHARTERS\HARRIS SI CHARTER 042612 (3).DOCX

(b)(5)

(b)(5)

D16

Plant :____________________ EA- (b)(5)

(b)(5)

Enforcement Summary for the Week of March 19, 2012

Outside of Scope

Region IV (b)(5)

(b)(5)

Contact: Mary Ann Ashley, NRR Enforcement Coordinator, 301-415-1073 [illegible]

Enforcement Summary for the Week of March 26, 2012

Outside of Scope

Region IV – (b)(5)

(b)(5)

Outside of Scope

Contact: Mary Ann Ashley, NRR Enforcement Coordinator, 301-41[illegible]

NRR ENFORCEMENT SUMMARY
July 16 – July 20, 2012

Outside of Scope

Region II

(b)(5)

Outside of Scope

Contact: Jeremy Bowen, NRR Enforcement Coordinator, 301-415-3471

6

NRR ENFORCEMENT SUMMARY
August 13 – 17, 2012

Outside of Scope

REGION IV

(b)(5)

Outside of Scope

Contact: Jeremy Bowen, NRR Enforcement Coordinator 301-415-3471

NRR ENFORCEMENT SUMMARY
September 10 – 14, 2012

Outside of Scope

REGION II

(b)(5)

Outside of Scope

Contact: Jeremy Bowen, NRR Enforcement Coordinator, 301-415-3471

NRR ENFORCEMENT SUMMARY
September 24 – 28, 2012

Outside of Scope

REGION II

(b)(5)

Outside of Scope

Contact: Jeremy Bowen, NRR Enforcement Coordinator, 301-415-3471

Howell, Art

From: Blount, Tom
Sent: Thursday, November 08, 2012 1:13 PM
To: Howell, Art
Cc: Lantz, Ryan; Werner, Greg
Attachments: (b)(5)

(b)(5)

Tom Blount
(Acting) Dir DRS R-IV
817-200-1146

D17

(b)(5)

(b)(5)

(b)(5)

10

Craver, Patti

From: Carlson, Robert
Sent: Friday, December 14, 2012 11:26 PM
To: Wengert, Thomas; Beltz, Terry; Feintuch, Karl; Chawla, Mahesh
Subject: FW: REQUEST: INSPECTORS TO STAFF THE BROWNS FERRY INSPECTION PROCEDURE 95003 SUPPLEMENTAL INSPECTION

PMs --

Please see following subject message and let me know if you're interested and qualified.

Thanks,

v/r

Bob

From: Monninger, John
Sent: Friday, December 14, 2012 3:45 PM
To: Pascarelli, Robert; Quichocho, Jessie; Carlson, Robert; Dudek, Michael
Cc: Lund, Louise
Subject: REQUEST: INSPECTORS TO STAFF THE BROWNS FERRY INSPECTION PROCEDURE 95003 SUPPLEMENTAL INSPECTION

Bob & Bob, Jessie, Mike:

Please see request below from Region II (inspectors to support BF inspection), and guidance from Louise regarding the need to discuss within DORL prior to sending any response to Region II. Please let me know of any potential staff (e.g., have the inspection skills and would be interested) from your branch. Region II is looking for feedback by 1/9, so we should be looking to vet any candidates we have the 1st of the year.

Thanks,
John

From: Lund, Louise
Sent: Friday, December 14, 2012 11:48 AM
To: Wilson, George; Khanna, Meena; Markley, Michael; Broaddus, Doug
Cc: Monninger, John
Subject: FW: REQUEST: INSPECTORS TO STAFF THE BROWNS FERRY INSPECTION PROCEDURE 95003 SUPPLEMENTAL INSPECTION

Not sure if we have qualified inspectors who would be available in the requested time frame, but wanted to make you aware of the request. If you think there's a fit, please come discuss with me before responding.

Thanks,

Louise

From: Nieh, Ho
Sent: Friday, December 14, 2012 11:42 AM
To: Evans, Michele; Ruland, William; McGinty, Tim; Muessle, Mary; Hiland, Patrick; Giitter, Joseph; Lubinski, John; Lund, Louise; Coffin, Stephanie; Davis, Jack; Bahadur, Sher; Cheok, Michael; Lee, Samson; Galloway, Melanie

D18

Cc: Jones, William; Croteau, Rick; Guthrie, Eugene; Howe, Allen
Subject: FW: REQUEST: INSPECTORS TO STAFF THE BROWNS FERRY INSPECTION PROCEDURE 95003 SUPPLEMENTAL INSPECTION

Dear colleagues...please see request for Browns Ferry Inspection support from Region 2.

They are looking for qualified inspectors that could lend a hand in specific areas.

Once they get a list of names from HQ and the regions, they'll select the help they need.

If you have former/current qualified inspectors who are interested and have expertise in the requested areas, please respond directly to Region 2 as indicated below by January 9.

Thanks,

Ho

Ho Nieh
Director, Division of Inspection and Regional Support
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
(301) 415-1004 (office)
(b)(6) (mobile)
(301) 415-3313 (fax)
ho.nieh@nrc.gov

From: Jones, William
Sent: Thursday, December 13, 2012 5:12 PM
To: Roberts, Darrell; Wilson, Peter; Clifford, James; Miller, Chris; West, Steven; Shear, Gary; Reynolds, Steven; OBrien, Kenneth; Kennedy, Kriss; Blount, Tom; Clark, Jeff; Howe, Allen; Lund, Louise; Monninger, John; Nieh, Ho
Cc: Croteau, Rick; Reis, Terrence; Christensen, Harold; Wert, Leonard; McCree, Victor; Jones, William; Guthrie, Eugene; Brown, Frederick; Munday, Joel; Yerokun, Jimi
Subject: REQUEST: INSPECTORS TO STAFF THE BROWNS FERRY INSPECTION PROCEDURE 95003 SUPPLEMENTAL INSPECTION

The purpose of this e-mail is to solicit staffing support for the Inspection Procedure (IP) 95003 supplemental inspection at the Browns Ferry Nuclear Power Station. The intent is to provide diversity of talent and opinion, as well as adding a degree of independence.

Although the inspection dates will not be finalized until the licensee has declared their readiness, we expect the bulk of the team inspection effort to occur between February 3, and May 21, 2013. The current schedule is as follows:

- February 4 - 8 – Site Orientation at Browns Ferry
- February 25 - 29 – Team Orientation and Training in Region II Office
- March 25 - April 5 – Team In-Office Inspection in Region II Office
- April 22 – May 3 – On-site Inspection at Browns Ferry
- May 13 – 24 – Inspection Review and Documentation in Region II

Our intent is to perform the inspection as a consolidated team to facilitate team work and to ensure that we efficiently integrate the safety culture aspects of IP 95003 into the inspection findings and observations. To further support and manage this effort, the IP 95003 team will be divided into the following five Areas: Safety Culture, Maintenance, Engineering, Problem Identification and Resolution (PI&R), and Operations.

The Browns Ferry 95003 inspection is a highly complex inspection that will require a large amount of inspection effort. To be successful, the inspection team need to be able to complete an intensive inspection effort with a minimal level of supervision. Inspection activities will include the review and evaluation of a large amount of complex information including; root cause analysis (RCA), program effectiveness reviews, corrective actions, performance improvement plans, and improvement metrics. Therefore members should have an appropriate level of experience to independently perform inspections and develop insights to support the following objectives within the scope of their inspection area:

- To provide the NRC additional information to be used in deciding whether the continued operation of the facility is acceptable and whether additional regulatory actions are necessary to arrest declining plant performance.
- To provide an independent assessment of the extent of risk significant issues to aid in the determination of whether an unacceptable margin of safety or security exists.
- To independently assess the adequacy of the programs and processes used by the licensee to identify, evaluate, and correct performance issues.
- To independently evaluate the adequacy of programs and processes in the affected strategic performance areas.
- To provide insight into the overall root and contributing causes of identified performance deficiencies.
- To evaluate the licensee's third-party safety culture assessment and conduct a graded assessment of the licensee's safety culture based on the results of the evaluation.

We are seeking an Area Lead and one additional inspector (Assistant Area Lead) for each of the inspection areas with expertise in one or more of the listed technical attributes:

Operations Area
- Power and refueling plant operations
- Operational decision making
- Work Control
- Control Room Operations
- Configuration control program implementation
- Human performance and error reduction management

Maintenance Area
- Maintenance Program Management/Implementation
- Maintenance rule program implementation
- Outage Management
- ISI program implementation
- General maintenance and testing program implementation
- Work control/scheduling/planning
- Equipment reliability program implementation

Engineering Area
- Engineering Program Management/Implementation
- CDBI
- Engineering inspection / supervision
- Fire protection
- Maintenance rule program implementation
- 10CFR50.59 requirements

PI&R Area

- PI&R Inspections/Audits
- Corrective Action Program Management/Implementation

Additionally, applicants who are to be considered for Area Lead positions should preferably have experience leading inspection teams, assessing licensee performance, developing inspection plans, and writing inspection reports. Note that the Area Lead for the Engineering area will also supervisor two engineering design review contractors.

We are seeking one Senior Reactor Analyst to support the inspection effort. This support role will include some travel, such as a site orientation travel to tour the facility, and assist the team regarding identification of safety significant SSCs to inspect. This individual will support risk characterization for any issues that are identified throughout the inspection effort.

Please have your inspectors provide a short description of their experience and expertise related to the area attributes for interested candidates. This will help the team lead and asst. team lead in assigning and overseeing inspection areas.

The safety culture assessors have been identified. Additionally, we are in need of an experienced administrative assistant to help the team leader. Interested persons should respond no later than COB on Jan 9. We intend to finalize the team staffing by January 18, 2013.

POC for information and questions regarding the above subject matter:

Eugene Guthrie
Branch Chief
Special Project, Browns Ferry
95003 Team Lead
404-997-4662

William B. Jones
Deputy Director, Division Reactor Projects, Region II
(404) 997-4501
(b)(6)

From: Giessner, John
Sent: Wednesday, August 29, 2012 10:26 AM
To: Mitlyng, Viktoria
Cc: Shah, Swetha; Riley (OCA), Timothy; Barker, Allan; Logaras, Harral; Heck, Jared; Chandrathil, Prema; Alley, David; Hills, David; Phillips, Charles
Subject: Re: Palisades startup

(b)(6) [redacted] I'll head to region this afternooon.

I could pull over at some time.

I rec this: swetha build some talking points and let dave a, dave h and sit concur and send to me.

We're talking 3 or 4 high level
(Sent from Blackberry)

From: Mitlyng, Viktoria
To: Giessner, John
Cc: Shah, Swetha; Riley (OCA), Timothy; Barker, Allan; Logaras, Harral; Heck, Jared; Chandrathil, Prema
Sent: Wed Aug 29 10:06:39 2012
Subject: Palisades startup

Jack,

I understand the plant is in Mode 3 and is on its way to startup. Could we set up a meeting this afternoon to discuss how we want to communicate about the NRC's position on Palisades returning to power. Tim and I had a conversation this morning about tough questions from congress and the media we are going to face and we want to make sure we have a consistent and strong message. I know you are very busy and short-handed right now but really hope we can do this today.

Thank you!

-Vika

Viktoria Mitlyng
Office of Public Affairs
US Nuclear Regulatory Commission
Region III
Lisle, IL 60532
Tel 630/829-9662
Fax 630/515-1026
e-mail: viktoria.mitlyng@nrc.gov

D 10