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

May 21, 2008

EA 07-047
07-194

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

Subject: FORT CALHOUN STATION NRC INSPECTION PROCEDURE 95002
SUPPLEMENTAL INSPECTION REPORT 05000285/2008006

Dear Mr. Bannister:

On April 9, 2008, the U.S. Nuclear Regulatory Commission (NRC) completed a supplemental inspection pursuant to Inspection Procedure 95002, "Inspection For One Degraded Cornerstone or any Three White Inputs in a Strategic Performance Area," at your Fort Calhoun Station. The enclosed inspection report documents the inspection findings, which were discussed on April 9, 2008, with you and other members of your staff. The onsite portion of the inspection concluded on March 20, 2008.

The purpose of this supplemental inspection was to examine your problem identification, root cause evaluation, extent of condition and extent of cause determinations, and corrective actions associated with multiple issues that placed Fort Calhoun Station in the Degraded Cornerstone Column of the NRC Reactor Oversight Process Action Matrix. This inspection also included an independent NRC review of the extent of condition and extent of cause for these same issues and an assessment of whether any safety culture component caused or significantly contributed to the issues. The issues, which were in the Mitigating Systems Cornerstone, included: (1) the Safety Systems Functional Failure Performance Indicator that was White in the 2nd quarter of 2007; (2) a White performance deficiency associated with inadequate maintenance and postmaintenance testing on a containment spray header isolation valve; and (3) a White performance deficiency associated with inadequate maintenance procedures and postmaintenance testing of a failed field flash relay and auxiliary contacts on an emergency diesel generator.

This report documents that the Fort Calhoun Station adequately addressed the Safety Systems Functional Failure Performance Indicator, and the White finding associated with inadequate maintenance and postmaintenance testing on a containment spray header isolation valve. However, Fort Calhoun Station failed to adequately address the White finding associated with inadequate maintenance procedures and postmaintenance testing of a failed field flash relay and auxiliary contacts on an emergency diesel generator. Specifically, your staff's assessment of a failure analysis of the failed auxiliary contacts did not adequately address a potential generic failure mechanism of a sticking contact actuator due to the inappropriate application of wet lubricant and build up of dust and debris. Past maintenance practices resulted in the application of wet lubricant that was a significant contributor to the failure of the emergency diesel generator. Additionally, at the time of the inspection, the timetable of actions to address the scope of extent of condition to other relays and contacts was not considered timely given the potential common mode failure mechanism of high resistance contacts due to poor past maintenance practices. Your staff was also actively engaged with the development and refinement of preventative maintenance strategies for relays and contactors at the time of the inspection. Consequently, the NRC was not able to effectively evaluate the robustness and adequacy of your future preventative maintenance plans at the time of the inspection. As a result, the White finding associated with Notice of Violation 05000285/2007011-03, "Failure to Provide Procedure for Safety-Related Maintenance Activities," will remain open pending a future inspection per NRC Inspection Procedure 95002 to verify that: (1) the concerns of extent of condition of inadequately maintained relays and contacts are appropriately assessed with regards to contactor binding and that adequate corrective actions are identified and implemented; and (2) to verify the completion and adequacy of the action items relative to future preventative maintenance of risk important components and subcomponents such as electrical relays and contactors.

As discussed in Section 06.01 of NRC Inspection Manual Chapter 0305, safety-significant inspection findings are carried forward for 4 calendar quarters or until appropriate licensee corrective actions have been completed, whichever is greater. Therefore, the White finding associated with the inoperable containment spray header isolation valve and the White Safety Systems Functional Failure Performance Indicator will no longer be considered in the assessment process starting the 2nd quarter of 2008. The White finding related to the failed diesel generator, which was identified in the 3rd quarter of 2007, will remain open and will be considered in the assessment process, pending the completion of a future NRC inspection to verify satisfactory completion of actions as discussed above or until the beginning of the 3rd quarter of 2008, whichever is greater. As a result, your Fort Calhoun Station, will be considered in the Regulatory Response Column (Column 2) of the NRC's Action Matrix starting the 2nd quarter of 2008. No other findings or violations of significance were identified during the inspection.

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

Sincerely,

Dwight D. Chamberlain

Dwight D. Chamberlain
Division Director
Division of Reactor Projects

Docket: 50-285
License: DPR-40

Enclosure:
NRC Inspection Report 05000285/200806
w/Attachment:
1) Supplemental Information
2) Inspection Plan

cc w/Enclosure:
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SUNSI Review Completed: ___ ADAMS: ☑ Yes ☐ No Initials: ___
☑ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ☑ Non-Sensitive
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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-285
License:	DPR-40
Report:	05000285/2008006
Licensee:	Omaha Public Power District
Facility:	Fort Calhoun Station
Location:	Fort Calhoun Station FC-2-4 Adm. P.O. Box 399, Highway 75 - North of Fort Calhoun Fort Calhoun, Nebraska
Dates:	March 10 through April 9, 2008
Inspectors:	Z. Dunham, Senior Resident Inspector (Team Leader) G. George, Reactor Engineer C. Long, Resident Inspector C. Osterholtz, Senior Resident Inspector A. Della Greca, Contractor, Beckman and Associates, Inc.
Accompanying Persons:	M. Hayes, Project Engineer (Training)
Approved By:	Dwight D. Chamberlain, Director Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000285/2008006; 03/10/2008 – 04/09/2008; Fort Calhoun Station, Supplemental Inspection 95002, "Inspection for One Degraded Cornerstone or any Three White Inputs in a Strategic Performance Area."

This inspection was conducted by senior resident and resident inspectors, an engineering inspector, and a contractor. No findings of significance were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

Cornerstone: Mitigating Systems

- N/A. The U.S. Nuclear Regulatory Commission conducted this supplemental inspection to assess the licensee's individual and collective evaluation of a 2nd quarter 2007 mitigating systems cornerstone White finding, a 2nd quarter 2007 mitigating systems White NRC Performance Indicator, and a 3rd quarter 2007 mitigating systems White finding. These findings and performance indicator collectively placed the Fort Calhoun Station in the Degraded Cornerstone Column (Column 3) of the NRC's Action Matrix from the 2nd quarter 2007 through the end of the 1st quarter 2008. The 2nd quarter 2007 White performance indicator associated with the safety system functional failure performance indicator was White because station reporting a cumulative six safety system functional failures during the previous four quarters. This performance indicator returned to Green in the 3rd quarter 2007. The 2nd quarter 2007 White finding, documented in NRC Inspection Report 05000285/2006018, was associated with improper valve maintenance activities on a containment spray header isolation valve rendering the valve inoperable for an entire operating cycle. The 3rd quarter 2007 White finding, documented in NRC Inspection Report 05000285/2007011, was associated with inadequate maintenance and corrective actions for a relay and contact failure in the field flash circuit of an emergency diesel generator rendering Emergency Diesel Generator 1 inoperable on two separate occasions.

  The NRC inspection team concluded that the licensee adequately evaluated the White finding associated with the containment spray header isolation valve maintenance, identified the root and contributing causes, implemented effective interim corrective actions and long term corrective actions to prevent recurrence, defined the extent of condition appropriately, and planned effective long term actions to address the extent of causes. As a result, this White finding and associated Notice of Violation 05000285/2006018-01, "Violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions Procedures, and Drawings"," is closed. Additionally, the team determined that the licensee adequately assessed the individual and collective aspects and contributors to the safety system functional failure performance indicator and identified appropriate actions as discussed in the inspection report. In addition, the team concluded that the licensee's evaluation of the inadequate corrective actions aspect of the Emergency Diesel Generator 1 relay maintenance White finding to be adequate and that acceptable interim and long term corrective actions were in place to assure that future significant conditions adverse to quality would be appropriately identified and evaluated in the licensee's corrective action program. As a result, Notice of Violation 05000285/2007011-02, "Inadequate Emergency Diesel Generator Corrective Measures," is closed.

However, the team determined that, although the licensee's evaluation of the Emergency Diesel Generator 1 relay failure identified the root and contributing causes, developed adequate corrective actions, and included plans to prevent recurrence of the failure of the emergency diesel generators, it failed to adequately assess the extent of condition. The licensee's assessment of extent of condition for the Emergency Diesel Generator 1 relay contact failure due to inappropriate lubrication was narrow and untimely. Specifically, the initial extent of condition scope was focused on the same relay type as the one that failed in the Emergency Diesel Generator 1 circuit, even though inappropriate lubrication was applied to other relay types. This narrow evaluation of the lubrication issues resulted in the licensee initially identifying only a population of five relays in components other than the emergency diesel generators. The licensee recognized that the extent of condition was narrow in February 2008, prior to this inspection, and expanded the scope to include other FID-1 relays that may have been inappropriately lubricated. However, the team concluded that the licensee's extent of condition was still too narrow in that the licensee failed to address the potential for sticking or binding of auxiliary contact actuators as a failure mechanism. Therefore, they failed to include safety-related FID-2 relays in the list of components to be evaluated and/or tested to assure their ability to perform their safety function. Additionally, the licensee's corrective actions to address the expanded extent of condition of lower risk significant relays were potentially untimely given that the licensee's actions depended on a preventative maintenance schedule over four operating cycles, approximately 6 years, to address the potential common cause failure mechanism of inappropriate application of lubricants. Assessing the operability status of all relays in a timely manner was important, given the common mode failure mechanism and the potential for multiple components, trains, or system functional failures during an event response.

During the inspection, Fort Calhoun Station entered a forced outage. Due to the team's questioning of the extent of condition, the licensee identified a population of 39 relays to be inspected during the forced outage. This inspection resulted in four relays not meeting acceptance criteria for contact resistance. The licensee determined that two of those relays needed further assessment and were tagged out of service in their safety position. This assessment is pending the shutdown of the facility to allow for as found testing of the components and is the subject of an unresolved item. The team also noted that, at the time of the inspection, the licensee was still making refinements to the overall preventative maintenance strategy to implement adequate maintenance on relays and contactors. Therefore, it was not clear that the licensee had a fully developed preventative maintenance plan that would assure that all of the correct maintenance would be implemented.

Consequently, the White finding associated with Notice of Violation 05000285/2007011-03 will remain open pending a future inspection per NRC Inspection Procedure 95002 to verify that: (1) the extent of condition of inadequately maintained relays and contacts is appropriately assessed with regards to contactor binding; (2) adequate corrective actions are identified and implemented;

and (3) the preventive maintenance and postmaintenance testing of risk-significant components and subcomponents, such as electrical relays and contactors, are properly evaluated and addressed.

The team determined that the licensee's common cause analysis of the individual issues was adequate and correctly identified underlying safety culture aspects which contributed to the events. As a result of the analysis, the licensee identified five focus areas, developed associated action plans, and implemented interim actions to help improve overall future plant performance. The licensee's focus areas consisted of Human Performance, Equipment Reliability, Latent Engineering Issues, Problem Identification and Resolution, and Safety Culture.

REPORT DETAILS

01 INSPECTION SCOPE

The U.S. Nuclear Regulatory Commission (NRC) performed this supplemental inspection in accordance with Inspection Procedure (IP) 95002, "Inspection for One Degraded Cornerstone or any Three White Inputs in a Strategic Performance Area," due to Fort Calhoun Station being in the Degraded Cornerstone Column (Column 3) of the NRC's Action Matrix. Fort Calhoun Station entered Column 3 in the 2nd quarter of 2007 as a result of a White performance indicator (PI) for safety system functional failures (SSFFs) coincident with a White finding in the Mitigating Systems Cornerstone related to improper maintenance and postmaintenance testing (PMT) of the containment spray header isolation Valve HCV-345. The SSFF PI subsequently returned to Green during the 3rd quarter of 2007. Additionally, Fort Calhoun Station received a second White finding for inadequate Emergency Diesel Generator (EDG), EDG-1, maintenance and corrective actions associated with a relay and contact failure in the EDG-1 field flash circuitry effective the 3rd quarter of 2007. Therefore, Fort Calhoun Station remained in Column 3 based on two White findings in the Mitigating Systems Cornerstone and pending the completion of this supplemental inspection. The White improper valve maintenance activity on Valve HCV-345 and the inadequate relay and contact maintenance associated with EDG-1 were identified in NRC "Final Significance Determination" letters, dated May 29 and December 7, 2007, respectively. The White SSFF PI was identified in the licensee's 1st quarter 2007 data submittal, on April 21, 2007. Details of the individual White findings were documented in Inspection Reports (IRs) 05000285/2006018 (Inadequate Maintenance of Valve HCV-345) and 05000285/2007011(Inadequate Maintenance Procedure and Corrective Actions of EDG-1).

The inspection objectives were to: (1) provide assurance that the root causes and contributing causes for the White findings and SSFF PI as described above are understood; (2) independently assess the extent of condition and the extent of cause; (3) independently determine if safety culture components caused or significantly contributed to the performance issues; and (4) provide assurance that Fort Calhoun Station's corrective actions are sufficient to address the root and contributing causes and to prevent recurrence of the performance deficiencies.

The licensee event reports (LERs) that contributed to the White SSFF PI are described below:

<u>LER 2006-002, "Inadequate Design Control Results in Potentially Insufficient Auxiliary Feedwater (AFW) Flow"</u>: The power supply to a safety related Flow Transmitter FT-1368 was from a non-safety related instrument bus. Previously, in 1997, the safety classification of the transmitter was upgraded from nonsafety related to safety related to assure that the associated recirculation flow valve would close to assure adequate auxiliary feed flow to the steam generators (SG), accounting for main steam safety valve setpoint tolerance or back-pressure accumulation. Although the transmitter's safety classification was upgraded, the licensee did not recognize the need to also upgrade the classification of the associated power supply.

<u>LER 2006-003, "Technical Specification Violation of Containment Air Coolers Due to Untimely Corrective Actions":</u> Torn dust boots on pneumatic actuators, indicating possible actuator leaks, were identified on two component cooling water supply valves to containment air coolers. In addition, an operability determination (which asserted the valves could perform their function)

was incorrect on five other component cooling water isolation valves. Therefore, multiple trains of containment cooling were unavailable simultaneously.

LER 2006-005, "Faulty Maintenance Renders One Train of Containment Spray System Inoperable": A containment spray header isolation valve was installed incorrectly for an operating cycle. The valve had been assembled incorrectly during a 2005 refueling outage. A single failure of the other spray header would have resulted in substantially reduced containment spray.

LER 2006-008, "Loss of Shutdown Cooling Due to Repressurizing Reactor Coolant System": During a refueling outage in 2006, a loss of shutdown cooling event occurred when reactor coolant pumps were secured resulting in a reduction in pressurizer spray flow. However, pressurizer heaters were not secured causing the reactor coolant system to pressurize resulting in automatic isolation of the shutdown cooling system.

LER 2007-003, "Inoperability of a Diesel Generator with Inoperable Containment Spray Pump from the Opposite Bus": The licensee determined that an EDG was inoperable from February 14 through February 16, 2007, following a failure of the diesel generator to properly start. The licensee subsequently identified that a containment cooling fan, powered from the opposite bus, had been inoperable for unrelated maintenance activities for approximately 2.5 hours resulting in only one operable containment cooler.

LER 2007-004: "Inadvertent Isolation of Containment Spray Due to Inadequate Test Procedure": The licensee identified that during containment spray actuation surveillance testing that both trains of containment spray would be rendered inoperable as a result of a previously implemented design change. The design change, implemented in 1990 for one train, and 2006 for the opposite train, inserted a cross-train dependency to eliminate the potential for a containment spray pump run out condition under certain circumstances.

Note: LER 2006-005 and LER 2007-003 are associated with the White findings of inadequate maintenance on Valve HCV-345 and EDG-1, respectively, and are assessed separately from the team's evaluation of the White SSFF PI. However, the team collectively evaluated all of the LER's and associated Root Cause Evaluations (RCE) in order to assess the adequacy of the licensee's common cause evaluation.

02 EVALUATION OF INSPECTION REQUIREMENTS

02.01 Problem Identification

a. Determine that the evaluation identifies who (i.e., licensee, self-revealing, or NRC) and under what conditions the issue was identified.

(1) Inadequate Maintenance and PMT of HCV-345

The licensee discovered the valve was assembled incorrectly on October 10, 2006, while performing maintenance on containment spray isolation Valves HCV-344 and HCV-345. The issue was documented in Condition Report (CR) 200604627 and an associated RCE. The performance deficiency self-revealed on September 13, 2006, when water discharged from the containment spray header indicating Valves HCV-344 and 345 were not properly seated.

The team determined that the licensee's assessment appropriately documented the identification of the issue and the conditions under which it was identified.

(2) Inadequate Maintenance Procedure and Corrective Actions for EDG-1 Relay Failure

RCE 2007-0725, EDG-1 Field Flash Functional Failure

On February 14, 2007, during the monthly performance test of EDG-1, the generator field did not flash. The licensee determined that a control relay in the electric generator Control Circuit Relay 2CR failed to energize, when the diesel engine reached the set speed, and apply to the generator field the 125 VDC required to ensure proper operation of the generator.

The Relay 2CR, a General Electric (GE) CR105 model contactor, is a vital component of the electric generator control circuit. When the EDG is started and the diesel engine reaches approximately 750 RPM, the Relay 2CR coil is energized and its main contacts close to apply 125 VDC and flash the generator field. When the generator has developed sufficient voltage, the voltage regulator controls the generator field and field flashing is no longer required. The control circuit of the Relay 2CR coil includes two normally closed auxiliary contacts of the same relay that are in series with the coil. These contacts that bypass voltage-dropping resistors, also in series with the coil, must be closed at the time that the relay is energized. This is to ensure that a full voltage is applied to the relay coil and that the relay is properly energized. Once the diesel generator field is self-sustained, the Relay 2CR is de-energized and the auxiliary contacts return to their normally closed state, in anticipation of the next EDG start demand. Troubleshooting determined that high resistance across the Relay 2CR auxiliary contacts prevented the relay coil from being energized. As a result, the generator field was not flashed and the generator did not develop the required voltage across its terminals.

This self-revealing issue was captured in CR 200700725 and evaluated in the associated root cause analysis report dated October 31, 2007.

The team determined that the licensee's assessment appropriately documented the identification of the issue and the conditions under which it was identified.

RCE 2007-0756, EDG-1 Unknown Inoperability

On February 16, 2007, during performance of the monthly test of EDG-1, aborted 2 days earlier (as discussed above), the licensee experienced a second field flash failure. Subsequently, the licensee determined that the Relay 2CR auxiliary contacts were stuck open. As indicated also above, the Relay 2CR auxiliary contact must be closed for the energization of the Relay 2CR to occur.

As a result of the field flash failure on February 14, 2007, the licensee replaced the auxiliary contacts that had displayed high resistance. During the replacement, a misalignment of the auxiliary contact assembly caused the Relay 2CR auxiliary contacts to stick open, following the PMT. The failure of the contacts in the open position resulted in a reduced voltage being applied to the relay coil, due to the voltage drop resistors being in series with the coil. The reduced voltage at the relay coil prevented the Relay CR from being energized and the generator field from being flashed.

This self-revealing issue was captured in CR 200700756 and evaluated in the associated root cause analysis report, Revision 2, dated March 3, 2008.

The team determined that the licensee's assessment appropriately documented the identification of the issue and the conditions under which it was identified.

(3) SSFF PI

LER 2006-002

The licensee's RCE indicated that the licensee identified the nonconforming auxiliary feedwater pump instrument power supply during the Equipment Reliability Optimization Project (EROP).

The team determined that the licensee's assessment appropriately documented the identification of the issue and the conditions under which it was identified.

LER 2006-003

The licensee's RCE provided that the NRC resident inspector identified that CR 200603071 and its associated operability evaluation conflicted with CR 200401672 (also NRC identified) on the hydrodynamic torque experienced by some of the licensee's 400 series butterfly valves. Subsequently, the component cooling water supply valves to containment coolers were declared inoperable.

The team determined that the licensee's assessment appropriately documented the identification of the issue and the conditions under which it was identified.

LER 2006-008

The licensee determined that the loss of shutdown cooling was self-revealing on November 27, 2006, when shutdown cooling automatically isolated following inadvertent pressurization of the reactor coolant system. Re-pressurization occurred while operators were equalizing boron concentration between the pressurizer and reactor coolant system during which reactor coolant pumps were secured.

The team determined that the licensee's assessment appropriately documented the identification of the issue and the conditions under which it was identified.

LER 2007-004

The licensee determined that the issue was self-identified on April 12, 2007. During conduct of a surveillance procedure, reactor operators identified that the test was deficient in that it rendered all containment spray inoperable during the surveillance.

The team determined that the licensee's assessment appropriately documented the identification of the issue and the conditions under which it was identified.

b. Determine that the evaluation documents how long the issue existed, and prior opportunities for identification.

(1) Inadequate Maintenance and PMT of Valve HCV-345

The licensee's evaluation states that Valve HCV-345 was returned to service on May 10, 2005, after three disassemblies in the 2005 refueling outage. The misaligned valve was discovered on October 10, 2006. After the 2005 refueling outage, during Cycle 23, the licensee installed a small pump to the low pressure safety injection system to mitigate the creation of gas voids in that system. The new pump was placed in service on February 16, 2006. After the pump was placed in service, the pressurized system leaked through Valve HCV-335, the interface valve between the low pressure safety injection system and the containment spray system, subsequently leaking through both containment spray header isolation Valves HCV-344 and HCV-345. Both valves experienced seat leakage and their respective spray headers were drained on seven occasions until a temporary modification established a constant drain through a drain valve on the spray header. The quantity of leakage drained from both spray headers was roughly the same quantity. Since the leakage from both valves was roughly the same, the licensee concluded that the leakage and subsequent draining did not represent an opportunity to identify the incorrectly assembled valve.

The team concluded that the evaluation appropriately documented the duration of the issue and that no additional opportunities existed for prior identification with the exception of the inadequate PMT following the 2005 valve reassembly, which if adequately performed, would most likely have revealed the incorrect valve maintenance.

(2) Inadequate Maintenance Procedure and Corrective Actions for EDG-1 Relay Failure

RCE 2007-0725, EDG-1 Field Flash Functional Failure

The licensee's RCE of the February 14, 2007, event determined that the generator field failure to flash was the result of high resistance across Relay 2CR auxiliary contacts that are in series with Relay 2CR coil. The maximum resistance value for these contacts stated in the EDG preventive maintenance procedure is 1 ohm. The licensee also calculated that 11 ohms would have been sufficient to prevent the relay from energizing. Following the field flash failure, the licensee measured contact resistance values ranging from 10 to 300 ohms. These high resistance values measured by the licensee were the result of contact oxidation due to normal aging of the relay, complicated by inappropriate lubrication of the relay auxiliary contacts. The wet lubricant applied to the plastic contact actuator apparently migrated to the metal contacts' surface attracting dust. The contact degradation resulting from the combined effect of these two causes developed, most likely, over a long period. It was assumed that the inoperable condition could not have existed prior to the previous successful EDG monthly test, 28 days earlier.

The licensee also evaluated missed opportunities to identify the condition and prevent the field flash failure. The team's review of the analysis determined that the licensee had both internal and external operating experience (OE) that indicated the susceptibility of the contacts to high resistance. As indicated in NRC IR 05000285/2007011, recent external OE with high resistance contacts was entered in the corrective action program but actions were not taken to address the condition in a timely manner. The licensee also had documented experience with high resistance readings with the contacts of the same relay, 2CR, and a similar relay, 3CR, in the generator control circuit. Although these internal records were dated 1989 and 1990, there was no indication that a periodic review of the condition was conducted or included in the preventive maintenance program.

Regarding the use of lubricants, GE documentation specifically indicated no requirements for lubrication of the specific components. Furthermore, when the licensee contacted GE to determine acceptability of a wet lubricant, Molykote 55M, a reply from GE specifically allowing such use was either not received or could not be found in the licensee's documentation. More recently, GE continued to discourage wet lubricants on the contact sliding mechanism because it would attract dust and cause wear of the actuator. As a potential example of sticking and binding, the team observed sluggish auxiliary contacts on a GE, Size 1, Relay CR106 motor starter that had been taken out of service and returned to the warehouse. The auxiliary contact assembly of the motor starter appeared to have been treated with a lubricant that had become sticky with age. The preventative maintenance procedures associated with GE Relays CR105 and CR106 allowed use of Molykote 55M lubricant on an as-needed basis, without specific instructions as to its application.

The team concluded that the evaluation appropriately documented the duration of the issue. The team also concluded that an adequate preventive maintenance program potentially would have given the licensee an opportunity to identify the contacts degradation prior to the event.

RCE 2007-0756, EDG-1 Unknown Inoperability

The licensee's RCE of the February 16, 2007, event determined that the generator field failure to flash was the result of inadequate PMT. Following the February 14 failure, the licensee replaced the Relay 2CR auxiliary contacts. A misalignment of the contact assembly resulted in the contacts failing open, following the energization of the relay during the PMT. The licensee theorized that improper removal of the contact assembly from the holding metal bracket to which they were attached resulted in a slight bending of the bracket itself and the consequent misalignment of the contact assembly. The forces imposed on the contact assembly by the energized coil resulted in the over-travel of the sliding mechanism and the consequent failure of the contacts in the open position. This condition existed from February 14-16, 2007.

As in the earlier event, the licensee reviewed internal and external OE to determine whether earlier opportunities existed to identify and correct the deficiency and prevent the EDG-1 field flash failure. The licensee's review identified several internal and external events related to inadequate PMT that resulted in unknown equipment inoperability conditions. The need for establishing adequate PMT criteria was captured in Procedure SEI-20, "Duties and Responsibilities of System Engineering." This document specifically instructed the system engineer to ensure that adequate PMTs were specified.

The team concluded that the evaluation appropriately documented the duration of the issue. The team also concluded that an adequate PMT would have allowed the licensee to identify the failure of the contacts in the open position prior to returning the EDG to service.

(3) SSFF PI

LER 2006-002

Regarding the nonsafety-related auxiliary feedwater instrument power supply, the licensee identified that the function of recirculation Valve FCV-1368 should have been to close on SG injection since initial plant design. The licensee identified various points at which revisions to both AFW calculations and modifications did not identify the need for Valve FCV-1368 to close during SG injection. Those included updates to the Updated Safety Analysis Report (USAR) maximum SG pressure of 1048 psia and then 1056 psia in 1997. In addition, the licensee identified that in 1997, the AFW calculation for minimum required AFW flow into the SGs FC05361, Revision 4, identified that the recirculation valve would need to be closed to supply the necessary flow of 180 gpm at 1056 psia, however no multidisciplinary review was conducted to evaluate the safety classification of the Valve FCV-1368 instrumentation. The licensee also stated that an April 1997 NRC inspection team identified the disconnect between the AFW flow calculation and the Valve FCV-1368 instrumentation. It was not until July 2006 that the licensee re-identified the disconnect between the calculation's need for Valve FCV-1368 to close to meet design basis flow and the nonsafety classification of Valve FCV-1368's instrumentation.

The team concluded that the evaluation appropriately documented the duration of the issue and that no additional opportunities existed for prior identification.

LER 2006-003

The licensee identified that it had been cognizant of the containment cooler issue since at least 2004 when the NRC issued a Green noncited violation (NCV) for failing to utilize OE on the hydrodynamic forces for these valves. The licensee identified that opportunities were missed in June 2006 when the system engineer failed to reference the hydrodynamic torque OE, CR 200401672, or an associated NRC identified NCV (refer to NCV 05000285/2004003-08, "Failure to Establish an Adequate Test Program for the Backup Nitrogen Supply Systems to the CCW Inlet and Outlet Valves to the Containment Air Cooling Units," for more details). In 2006, the NRC resident inspectors identified the conflict between the 2006 operability evaluation and CR 200401672. Although most of this issue was NRC identified, the RCE did recognize these missed opportunities.

The team concluded that the evaluation appropriately documented the duration of the issue and that no additional opportunities existed, other than those identified by the licensee, for prior identification.

LER 2006-008

The licensee's root cause analysis treated the loss of shutdown cooling as a discrete event in that a loss of shutdown cooling had not occurred previously at the facility due to inadvertent repressurization of the reactor coolant system during boron equalization. The licensee also evaluated the potential for prior opportunities to identify or prevent the issue.

The team concluded that the licensee's determination that the event was discrete was accurate and that no additional opportunities existed for prior identification.

LER 2007-004

The licensee determined that inoperability of both trains of containment spray during emergency safeguards actuation system surveillance testing had existed since 2006 when the design change was made to the valve and pump interlock on the Train B, which was similar to the change made in 1990 to the Train A. With the modification implemented on the Train B in 2006, both trains would be rendered inoperable during the test. These modifications to the discharge valve logic were performed in lieu of a piping modification to address a pump run-out condition. The quarterly surveillance test was typically conducted over approximately 3 hours. The licensee identified that the assumptions made in the 1990 modification to the containment spray Train A interlock were inadequate. The modification package assumed that offsite power was sufficient to ensure pump operability during testing. Additionally, the licensee identified that the 1990 modification package was performed on a weekend with the plant unable to return to power without its completion. These surveillance procedures did not receive appropriate reviews because they were not included in the modification package in 1990 and again in 2006. This error was also carried forward in 2006 in which the licensee relied on the 1990 modification package without additional scrutiny. The RCE also provided that an identification opportunity was missed during the design of the modification in which a contracted engineer was utilized and did not review the modification in detail.

The team determined that the licensee's assessment appropriately determined how long the issue existed and prior opportunities for identification.

c. Determine that the evaluation documents the plant specific risk consequences (as applicable) and compliance concerns associated with the issue(s) both individually and collectively.

(1) Inadequate Maintenance and PMT of Valve HCV-345

The team noted that the licensee concluded that Technical Specification 2.4(1)a.iv was violated each time the reactor was made critical on May 31 and June 13, 2005, and May 6, 2006. The plant specific risk associated with the finding, as evaluated with the NRC significance determination process was 4.61E-6 per year (White), as documented in NRC IR 05000285/2006018. The condition was corrected soon after it was identified.

The team concluded that the evaluation appropriately documented the risk consequences and applicable compliance concerns.

(2) Inadequate Maintenance Procedure and Corrective Actions for EDG-1 Relay Failure

RCE 2007-0725, EDG-1 Field Flash Functional Failure

The licensee's evaluation indicated that while a second EDG was undergoing a functional test on February 15, 2007, that for a period of 36 minutes both EDGs were unavailable. During the same period, the plant was exposed to a potential station blackout that could have challenged the ability of the system to safely shutdown the plant. The root cause analysis did not specifically address the quantitative risk consequences of the event. However, the licensee discussed the risk significance with the NRC during the original evaluation of the event by the NRC. As indicated in the NRC Final Significance Determination of a White Finding and NOV, dated December 7, 2007, the licensee's analysis and conclusions were included as an enclosure to a Regulatory Conference Meeting Summary issued on November 13, 2007. In this enclosure, based on a 14-day exposure time, the licensee determined that the change in core damage frequency as a result of the EDG-1 failure was 5.1E-6/year. The licensee's conclusions were consistent with an NRC risk assessment of 5.4E-6/year. Based on these results, both the licensee and the NRC concluded that the significance of the event was of low to moderate risk (White).

The team concluded that the evaluation appropriately documented the risk consequences and applicable compliance concerns.

RCE 2007-0756, EDG-1 Unknown Inoperability

The licensee documented a qualitative assessment of the unknown inoperability of the EDG-1. Specifically, the licensee indicated that the unavailability of EDG-1 also resulted in the unavailability of both containment air cooling and Filtering Fans VA-3A and VA-3B, leaving one small containment cooler available for cooling. The unavailability of the fans was 2 hours and 46 minutes, while Fan VA-3B was undergoing surveillance testing. This inoperability of the containment coolers was the subject of LER 05000285/2007-03 dated April 17, 2007.

The NRC evaluated and documented the unavailability of EDG-1 due to inadequate PMT in IR 05000285/2007011. The NRC evaluation concluded that the finding was of very low safety significance (Green) and an NCV was identified (see NCV 05000285/2007011-01, "Inadequate Emergency Diesel Generator Postmaintenance Test," for more details).

The team concluded that the evaluation appropriately documented the risk consequences and applicable compliance concerns.

(3) SSFF PI

LER 2006-002

The licensee performed a qualitative risk assessment to address the nonconforming nonsafety-related auxiliary feedwater instrument power supply. Since the valve's control power source was classified as nonsafety, but was still supplied by a nonsafety source built from nuclear grade components, the licensee classified the risk as low. The team agreed that the probability was low for the nonsafety instrument power source failing and causing the valve to spring open on injection. The team questioned the licensee's probabilistic risk model and found that a change was pending to add the valve's closure function to the probabilistic risk model for motor-driven AFW success.

The licensee identified compliance aspects in that AFW pump FW-6 was declared inoperable. Technical Specification 2.5 required two trains of AFW to be operable. The licensee also documented in LER 2006-002 and CR 200602855 the USAR design requirements on the recirculation valve that were not followed and contributed to the issue.

The team concluded that the evaluation appropriately documented the risk consequences and applicable compliance concerns.

LER 2006-003

The licensee performed a qualitative risk analysis for the inoperable containment air coolers and determined the risk to be low assuming that the two remaining containment fan coolers would be operable and the other two degraded fan coolers would be functional for at least 2 hours. The team conducted an independent assessment of the risk utilizing the NRC's significance determination process Phase 2 pre-solved notebook and concurred with the licensee's assessment. The licensee also identified a noncompliance with Technical Specification 2.4 for the containment coolers.

The team concluded that the evaluation appropriately documented the risk consequences and applicable compliance concerns.

LER 2006-008

The licensee qualitatively determined the risk to be low because of a redundant capability to remove decay heat from the reactor via the SGs, which were available during the event. The licensee also identified the compliance aspects as part of the risk assessment. Specifically, the licensee failed to meet Technical Specification 2.11 which required that two decay heat removal loops be operable and one be in operation. The NRC previously assessed this event as a Green NCV (see NRC Inspection Report 05000285/2007002-03, "Loss of Shut Down Cooling Due to Inadequate Procedure," for more details).

The team concluded that the evaluation appropriately documented the risk consequences and applicable compliance concerns.

LER 2007-004

The licensee concluded that the risk of the isolation of both trains of containment spray was of very low significance due to the low probability of a loss of offsite power coincident with a main steam line break or large break loss of coolant accident. The licensee also credited available operator action to take the respective EDG out of local control which would have allowed one train of containment spray to be started in accordance with emergency operating procedures (EOPs). Operator action was also credited to take the respective spray header valve out of override which would have allowed one train of containment spray to be started, also in accordance with EOPs. The licensee also credited the operation of the containment air coolers to mitigate these accidents. Additionally, the licensee identified nonconformances with USAR, Sections 14.12 and 14.15, for the accident analysis associated with a main steam line break inside containment and loss of coolant accident, respectively.

The team concluded that the evaluation appropriately documented the risk consequence and applicable compliance concerns.

02.02 Root Cause, Extent of Condition, and Extent of Cause Evaluation

a. Determine that the problem was evaluated using a systematic method(s) to identify root cause(s) and contributing cause(s).

(1) Inadequate Maintenance and PMT of Valve HCV-345

The licensee's root and contributing causes were evaluated using events and causal factors analysis to identify the events and conditions that led up to the event to identify the root and contributing causes.

The team considered the licensee's method of analysis was systematic and appropriate for the significance of the condition.

(2) Inadequate Maintenance Procedure and Corrective Actions for EDG-1 Relay Failure

RCE 2007-0725, EDG-1 Field Flash Functional Failure

The licensee originally considered the field flash relay failure to be a simple component failure requiring an apparent cause evaluation. Following prompting by the NRC, the licensee raised the significance level of the event and initiated a root cause analysis. The licensee's analysis consisted of a sequence of events, a barrier analysis, and an event and causal factor chart. The licensee concluded that the root cause of the high resistance identified in Relay 2CR was the result of a lack of preventive maintenance strategy for the Relay 2CR auxiliary contacts.

The team considered the licensee's method of analysis appropriate for the significance of the condition.

RCE 2007-0756, EDG-1 Unknown Inoperability

The licensee used systematic methods to identify the root cause of the events that led to the same auxiliary contacts of the same EDG relay failing in the open position. The methods used included a sequence of events, a barrier analysis, and an event and causal factor chart. The licensee concluded that the root cause of the event was PMT that is lacking in specific guidance, and is over-reliant on the skills and knowledge of planners and engineers.

The team considered the licensee's method of analysis appropriate for the significance of the condition.

(3) SSFF PI

LER 2006-002

The licensee applied a timeline review to address the events that led up to the July 7, 2006, discovery of the nonqualified power supply for Valve FCV-1368. The licensee also applied a causal factor and failed barrier analysis. The licensee's findings included that engineering calculation Procedure PED-QP-3, "Calculation, Preparation, Review and Approval," Revision 13, did not provide guidance if multiple engineering disciplines are affected by one change to a calculation, safety function, or design basis.

Additionally, there was a time pressure aspect in which an April 1997 NRC inspection team identified the discrepancy between Calculation FC05361, Revision 4, and the safety classification of the instrumentation for Valve FCV-1368. However, an operability evaluation to support plant startup in April 1997 was inadequate because of time pressure on engineering due to the pending plant startup. This evaluation was relied on until July 2006 when the design control issue was recognized.

The team considered the licensee's method of analysis appropriate for the significance of the condition.

LER 2006-003

The licensee assessed the issue utilizing a timeline of events beginning in May 2004 with the licensee's identification of a torn dustboot and the NRC's identification of applicable OE on hydrodynamic forces action on butterfly valves. Although the licensee also evaluated this issue utilizing an events and causal factors tree, the timeline appeared to be the dominant tool in the root cause.

The team considered the licensee's method of analysis appropriate for the significance of the condition.

LER 2006-008

The licensee assessed the loss of shutdown cooling event utilizing a timeline and an events and causal factors chart. The evaluation also considered a separate plant evolution that occurred on April 30, 2007. This other evolution involved a plant shutdown that utilized the same reactor coolant pump shutdown sequence described in LER 2006-008. The licensee conducted a comparison of the two different evolutions to determine how two separate operating crews executed the same procedure and plant evolution, with one however resulting in the loss of shutdown cooling.

The team considered the licensee's method of analysis appropriate for the significance of the condition.

LER 2007-004

The licensee applied a fault tree and a created a timeline of events that led to the discovery of both trains of containment spray being inoperable during surveillance testing. The licensee also utilized a human performance failure modes analysis and a failed barrier analysis to assess administrative/programmatic aspects of the issue.

The team considered the licensee's method of analysis appropriate for the significance of the condition.

b. Determine that the root cause was conducted to a level of detail commensurate with the significance of the problem.

(1) Inadequate Maintenance and PMT of Valve HCV-345

The licensee's root cause analysis included a review of maintenance planning processes, maintenance and PMT records, CRs, standing orders, departmental policies, and interviews with key engineering and maintenance personnel. The licensee identified two root causes: (1) maintenance procedure flexibility resulting in deletion of risk important steps; and (2) inadequate acceptance criteria during the PMT process. In addition, two contributing causes were identified: (1) maintenance personnel did not recognize the significance of proper drive shaft alignment of the valve; and (2) incorrect parameters were used to assess the valve position during the PMT.

The team considered the licensee's method of analysis appropriate and to a level commensurate for the significance of the condition.

(2) Inadequate Maintenance Procedure and Corrective Actions for EDG-1 Relay Failure

RCE 2007-0725, EDG-1 Field Flash Functional Failure

The licensee's evaluation included the following: (1) a barrier analysis related to human performance in the event; (2) a barrier analysis pertaining to administrative and programmatic causal factors; (3) an analysis of management oversight issues; (4) a detailed time line of the event and associated corrective actions; (5) an extent of condition review; (6) an OE review of internal and external events; (6) a detailed description of the electric generator control circuit and components; (7) results from laboratory tests conducted on the failed auxiliary contact assembly; and (8) an analysis of underlying safety culture issues.

The team considered the licensee's method of analysis appropriate and to a level commensurate for the significance of the condition.

RCE 2007-0756, EDG-1 Unknown Inoperability

The licensee's analysis included the following: (1) an evaluation of human performance issues related to the event; (2) an analysis pertaining to administrative and programmatic issues; (3) a review of management oversight issues; (4) a review of equipment related issues and details of the relay contacts failure mode; (5) a detailed time line of the event and associated corrective actions; (6) an extent of condition review; (7) an OE review of internal and external events; (8) a barrier analysis of the event itself; (9) an evaluation of the root cause analyses performed by the licensee since 2005; and (10) an analysis of potential underlying safety culture issues.

The team considered the licensee's method of analysis appropriate and to a level commensurate for the significance of the condition.

(3) SSFF PI

LER 2006-002

For the nonsafety-related auxiliary feedwater power supply, the licensee utilized a timeline dating back to plant startup in 1974. This was necessary to track the design history, modification history, and associated calculation history in order to determine the missed opportunities to identify the issue.

The team considered the licensee's method of analysis appropriate and to a level commensurate for the significance of the condition.

LER 2006-003

For the inoperable containment air coolers, the licensee assessed the issue utilizing a timeline of events beginning in May 2004 with the licensee's identification of a torn dustboot and the NRC's identification of applicable OE on hydrodynamic forces action on butterfly valves. Although the licensee also evaluated this issue utilizing an events and causal factors tree, the timeline appeared to be the dominant tool in the root cause. The licensee determined that inadequate design basis document information resulted in the engineer incorrectly establishing the basis for operability of the Series 400 HCV valves.

The team considered the licensee's method of analysis appropriate and to a level commensurate for the significance of the condition.

LER 2006-008

For the loss of shutdown cooling event, the licensee determined that a failure to apply sound operator fundamentals was the root cause in addition to determining that an inadequate Procedure OP-3A, "Plant Shutdown," Revision 66, was a contributing cause in that it did not contain instructions or cautions to the operators to secure pressurizer heaters with no reactor coolant pumps running. The licensee also determined that a lack of supervisory oversight contributed to the event.

The team determined that the licensee's root cause analysis, although conducted to a level of detail commensurate with the significance of the issue, failed to properly characterize one of the causes. Specifically, the team concluded that the inadequate Procedure OP-3A was a second root cause to the event and not just a contributing cause. The team's conclusion was based on the fact that the inadequate procedure was the only cause in the licensee's analysis, that if corrected, would most likely prevent recurrence of the event. The team also noted that the root cause analysis did not establish why the shift manager was distracted and not available to provide adequate supervisory oversight during the evolution or why the shift technical advisor was not in the control room during the implementation of portions of Procedure OP-3A which lead to the loss of shutdown cooling.

LER 2007-004

The licensee identified the root cause as an oversight error in evaluating the operability of containment spray components during performance of surveillance tests following a modification to containment spray Train A. Specifically, an interaction table created in the modification package, specifically to address surveillance testing, assumed that offsite power was sufficient to ensure pump operability during testing and that EDG operability was not needed. The licensee identified that another assumption was that manual operator action could be substituted for automatic action to align a system for accident response. The licensee identified that this misconception for manual action was identified under CR 200200632 and that this was another opportunity to identify this issue. The licensee also attributed a contributing cause to system complexity due to the cross train system complexity.

The team concluded that in general that the licensee conducted the RCE to a level of detail commensurate with the safety significance. However, the team did identify a weakness in the licensee's assessment. The team considered that, although the system design was complex, it was not a contributing cause. The team concluded that a lack of understanding of the design of the system would be a more appropriate contributing cause versus the complexity of the system.

c. Determine that the RCE included a consideration of prior occurrences of the problem and knowledge of prior OE.

(1) Inadequate Maintenance and PMT of Valve HCV-345

The licensee's evaluation considered external OE from 1990 to 2005 using an industry database search. In addition to OE, the licensee reviewed CRs and RCEs beginning in January 2005. The licensee's search identified two events similar to the valve misalignment identified at the facility. The licensee's review of these similar events determined that the events were plant specific and that no further review was required. The licensee determined that the review was incorrect and prior opportunities were missed to discover a generic issue. The licensee generated CR 200605352 to capture the missed opportunity.

The team concluded that the evaluation appropriately considered prior opportunities for identification and other occurrences.

(2) Inadequate Maintenance Procedure and Corrective Actions for EDG-1 Relay Failure

RCE 2007-0725, EDG-1 Field Flash Functional Failure

The licensee's review of external OE identified several events that directly related to these conditions and causes. For instance, OE Report 22650, "Emergency Diesel Output Breaker did not Close Within the Required Time," was received by the licensee on May 19, 2006. The review of this OE indicated that high resistance across voltage regulator relays caused the output breaker to fail. Similarly, in OE 21865, "Emergency Diesel Generator Failed to Reach Rated Voltage During Monthly Surveillance," troubleshooting showed that high resistance existed across micro switches. In another OE example (OE 23357 and OE 24231), a contactor auxiliary contact did not return to its normal position after engine operation. As a result of these and similar OEs, the licensee concluded that there were missed opportunities to take corrective actions prior to the failure on February 14, 2007. The licensee's review also determined that, since the GE model CR105 relay was used in multiple systems, various licensee personnel would have reviewed OE reports related to this relay, but no single engineer or other personnel would have reviewed all the reports for applicability to the station. Therefore, the licensee concluded that a contributing cause of the field flash failure event was that the OE program did not facilitate adequate reviews of OE that spanned multiple plant systems.

The licensee also reviewed internal CRs and work orders related to the event and to the root and contributing causes. The licensee determined that only one work order was directly related to the failed relay. However, the licensee also provided that there were many work orders associated with the Relays 2CR and 3CR, as well as other similar relays with auxiliary contacts in other systems. The licensee concluded that internal OE existed to indicate that a PM activity on Relay 2CR contacts was warranted prior to the EDG-1 failure. In addition, the licensee concluded that internal OE reports were not consistently evaluated in the OE Program. As a result, the licensee considered the failure of the OE program to adequately assess both external and internal OE on this issue to be a contributing cause.

The team concluded that the evaluation appropriately considered prior opportunities for identification and other occurrences.

RCE 2007-0756, EDG-1 Unknown Inoperability

The licensee's review of OE related to this event concluded that issues related to PMT had been captured in an internal document, Procedure PED-SEI-20, "Duties and Responsibilities of System Engineering." This document instructed the system engineer to ensure that the PMT was correctly specified and periodically reviewed. Therefore, the licensee concluded that the recommendations of Procedure PED-SEI-20 were not consistently implemented within the system engineering department and represented a missed opportunity to ensure that the PMT adequately supported both functionality and operability testing. In addition, the licensee conducted a review of other internal OE reports, CRs, and work orders, which indicated weaknesses in reinforcing high standards of performance, tolerance of workers making choices that were inconsistent with management expectations, and reluctance by management to confront performance that did not meet their expectations.

The team concluded that the evaluation appropriately considered prior opportunities for identification and other occurrences.

(3) SSFF PI

LER 2006-002

The licensee evaluated both internal and external OE to determine whether or not prior opportunities existed to identify or prevent the occurrence of the non-qualified power supply to AFW FCV-1368. The licensee identified numerous internal OE reports that documented misidentifying safety-related equipment and its functions, and of procuring nonsafety resources for safety-related equipment. However, the licensee did not consider any of these examples to provide a direct precursor that could have prevented the issue with Valve FCV-1368.

The team concluded that the evaluation appropriately considered prior opportunities for identification and other occurrences.

LER 2006-003

The licensee's assessment identified prior OE, CR 200401672 and the associated NCV, as discussed earlier in this report, as missed opportunities to prevent the operability evaluation issue with the 400 series valves.

The team concluded that the evaluation appropriately considered prior opportunities for identification and other occurrences.

LER 2006-008

The licensee identified other losses of shutdown cooling occurrences in its OE review from 1998 and 1999. In both cases, the loss shutdown cooling was not due to control room operator error. Similar internal OE identified loss of secondary heat removal issues associated with inadequate procedures.

The team concluded that the evaluation appropriately considered prior opportunities for identification and other occurrences.

LER 2007-004

The licensee identified external OE in which industry errors in preparation and implementation of modifications resulted in forced outages, loss of system availability, potential common mode failures, and equipment damage. The licensee's response to this OE, documented in CR 200504919, concluded that there was applicability to the design process but it was found to not be a significant contributor. As a result, no action was taken.

The licensee conducted an internal OE review and noted that CR 200502838 identified that the Valve HCV-344 was not logged as inoperable due to containment spray Pump SI-3C being inoperable for preventative maintenance. Although this CR precedes this root cause analysis, the licensee identified this case as a missed opportunity because the CR acknowledged the cross-train interlock dependency but did not identify the surveillance testing issue.

The team concluded that the evaluation appropriately considered prior opportunities for identification and other occurrences.

d. Determine that the RCE addresses the extent of condition and the extent of cause of the problem.

(1) Inadequate Maintenance and PMT of Valve HCV-345

The licensee's evaluation concluded that the extent of condition, incorrect assembly of a valve coupled with inadequate PMT requirements of components that fail to reveal conditions other than correct operation, was most likely limited to the prior maintenance activities associated with Fisher Vee-Ball valves, HCV-341, HCV-344, and HCV-345. The licensee evaluated these valves for any assembly concerns that may have resulted in inoperability and did not identify any latent issues. However, from a review of past work orders associated with these valves, the licensee identified that the work documents showed inconsistencies in the selection of PMT applied to the work orders for similar past work. In addition, the criteria for selecting PMT in several work planning documents did not meet guidelines of the applicable valve program. For example, the licensee identified that the Planners Desk Top Guide, the document used to help in the selection of PMT, was not reconciled with requirements for testing in the Air Operated Valve Program Plan, PED-SEI-40. The licensee generated CR 200605350 to address the inconsistencies. Additional PMT corrective actions were documented in CR 200702160. The team concluded that the licensee's extent of condition review was appropriate.

The licensee's extent of cause review did not evaluate the root causes separately. As a result, the licensee determined that the extent of cause of procedure flexibility and inadequate PMT had the potential to exist only in nonsafety related pumps and air operated ball and butterfly valves that are not containment isolation valves. The team determined that the evaluation focused on combining the two root causes. The team concluded that an appropriate extent of cause evaluation would have evaluated other maintenance activities, including maintenance on components other than valves, such as pumps and electrical components, for adequacy of procedures and PMT. However, the team's independent review did not identify the cause to exist in other sampled components and systems and the team noted that the licensee had implemented appropriate interim corrective actions to review maintenance work orders and procedures for adequacy of the instructions and PMT. The licensee also planned to address in general the aspects of flexible maintenance procedures and inadequate PMT through the focus area action plan associated with the equipment reliability focus area. The licensee documented the team's observation of the narrowly focused extent of cause evaluation in CR 200801682.

(2) <u>Inadequate Maintenance Procedure and Corrective Actions for EDG-1 Relay Failure</u>

<u>RCE 2007-0725, EDG-1 Field Flash Functional Failure</u>

The licensee's analysis evaluated extent of condition and concluded that control circuit devices, such as relays, control switches and process switches, can exhibit high contact resistance and render the control circuit inoperable. Therefore, the extent of condition was that other plant circuits were susceptible to high contact resistance. Initially, the licensee's actions to address the extent of condition were limited to EDG circuit components. Subsequently, the licensee expanded the scope of extent of condition to include functional importance determination (FID), Critical 1 (FID-1), CR105 relays. As a result of this review, the licensee identified five additional components requiring resistance checks: (1) the shutdown cooling suction header isolation Valves HCV-347 and HCV-348 relay contacts were checked for resistance and found to be acceptable; (2) the containment sump suction isolation Valves HCV-383-3 and HCV-383-4 were scheduled for testing during the 2008 refueling outage; and (3) the turbine driven AFW Lube Oil Pump LO-39-MS was scheduled for the 2008 refueling outage.

The team's review of the corrective actions also determined that, as a result of commitments to the NRC related to a NOV, LIC-07-0120, the licensee planned to identify and develop maintenance strategies for FID-1 and FID-2 relays as part of the EROP. Additionally, on February 13, 2008, the licensee added corrective actions to replace the auxiliary contacts of the five components discussed above and to identify and correct FID-1 non-CR105 contacts in plant systems where lubrication may have been applied without vendor concurrence.

The team's evaluation of the licensee's extent of condition concluded that, although the root cause analysis correctly recognized the potential for high-resistance contacts existing in a multitude of safety-related circuits and components, the application of the conclusions were narrowly focused and untimely. Specifically, the licensee failed to recognize that the GE type CR106 relays are identical to the CR105 relays, except that they include thermal overload relays. As a result, the CR106 relays were not included in the original review. Additionally, the licensee failed to recognize that the lubrication of the relay auxiliary contacts was a potential common cause failure affecting the FID-2 as well as the FID-1 CR105 and CR106 relays. Therefore, the exclusion of FID-2 relays from the original scope of review was inappropriate.

During the inspection, the station entered a forced outage due to an unrelated plant scram. Due to the team's questioning of the extent of condition, the licensee identified a population of 39 relays requiring inspection. These relays, involving both FID-1 and FID-2 components, were subsequently inspected during the forced outage. The licensee determined the population of affected components by conducting interviews with electrical maintenance technicians to determine what types of components may have had lubricant inappropriately applied in the past and then comparing that population of affected components to previously identified FID-1 and FID-2 components. Although, through this process, the licensee probably identified the majority of the population of affected components, given the impromptu method for identifying the expanded scope of review, the team's level of confidence that the licensee had identified all of the potentially affected components was low. For example, the starter associated with the fuel transfer pump for the diesel-driven auxiliary feed pump was not added to the list of relays requiring inspection until prompted by the team. Nonetheless, the team concluded that the testing of the selected components would provide valuable insights on the extent of condition and the need for further actions.

The licensee's forced outage inspection identified four components with as found contact resistance that exceeded the licensee's established acceptance criteria of < 1 ohm. These components included main steam bypass Valves HCV-1041C and HCV-1042C, volume control tank outlet Valve LCV-218-2, and the high head safety injection to chemical volume control system cross-tie isolation Valve HCV 308. The licensee documented the as found condition of the relays in CR's 200801763, 200801815, 200801768, and 200801780, respectively. The auxiliary contacts for HCV-308 were replaced and the valve declared operable. No immediate safety concerns existed for the other components. The licensee determined that two of those relays (FID-2 components) associated with main steam bypass Valves HCV-1041C and HCV-1042C needed further assessment to demonstrate operability. As an interim action, the licensee tagged the valves in their closed safety position. The licensee's final assessment is pending until the shutdown of the facility to allow for as found testing of the valves. The licensee evaluated the as found resistance checks for the other components that were checked during the forced outage and concluded that the components were operable considering the low contact resistance that was measured and past acceptable performance of the associated components (i.e. no previous failures had occurred with components associated with the potentially affected relays and auxiliary contacts). Pending the NRC's final evaluation of the licensee's assessment of the as found condition of Valves HCV-1041C and HCV-1042C, an unresolved item (URI) is opened to review any potential regulatory and risk implications (URI 05000285/2008006-01, "High Contact Resistance on Main Steam Bypass Valve Relay Contactors").

The team reviewed failure analysis report, "Failure Analysis of GE CR105 X 300 Auxiliary Contact Assemblies," dated July 2007. This analysis, conducted by a vendor, was done to determine the failure mechanism for the failed EDG-1 relay and auxiliary contact. The report concluded the following:

1. "Resistance measurements performed by SwRI [vendor] suggest these electrical contacts were capable of performing adequately. (The unusually

high resistance of the contact set in the lower section of switch DG-1 (Sample 712) was attributed to the improperly installed spring that was wrapped around the moving-contact bar.)"

2. "Debris in the form of a single large particle may have been trapped in the moving interface between the case and the actuator of auxiliary contact assembly DG-1(upper) (Sample 711). This could have caused the mechanism to bind and result in high resistance of the contacts. The Molykote 55M served as a media to trap debris in the interface. The large particle was not found so this is speculation."

The team noted that the licensee's analysis of extent of condition focused on the material condition of the electrical contacts being the source of the high resistance and did not consider mechanical binding between the case and the auxiliary contact actuator to be probable. The team concurred that the EDG-1 relay contact failure was most likely due to a buildup of contaminants on the contacts due to the past application of Molykote 55M. However, the team also considered the potential for mechanical binding or sticking, as discussed in the vendor report, to be another potential generic failure mechanism of inappropriately lubricated relays and actuator contact assemblies that the licensee had failed to adequately address in the root cause analysis.

The licensee's evaluation of extent of cause determined that similar contacts exist in multiple applications in the plant, both FID-1 and safety related, and that these contacts are similarly susceptible to high resistance. As a result, the licensee concluded that the extent of cause was lack of comprehensive preventive maintenance strategy for contacts.

The team considered the licensee's conclusions of extent of cause to be narrow. While the licensee correctly recognized that a lack of preventive maintenance affected contacts in a multitude of circuits and that a comprehensive preventive maintenance program for contacts was appropriate, the licensee failed to consider in the RCE that an inadequate preventive maintenance program could exist in other critical plant components, such as breakers, pumps, valves, etc. For example, the licensee experienced some failures in medium voltage as well as low voltage circuit breakers that involved hardening of grease which could have been the result of aging as well as inadequate preventive maintenance. For instance, as described in Section 02.04(2) discussed later in this report, an evaluation of a breaker anomaly associated with the FW-2B 4160 Volt circuit breaker found that a contributing cause was attributable to hardening of the lubrication. Additionally, an apparent cause analysis for CR 200704449, which documented inconsistent results obtained from trip testing of Breaker MCC-4A2-B04, provided that the cause of the failure was hardening of the grease due to the aging of the breaker. Regarding all breakers, the licensee had established a component replacement program, as applicable. Although the licensee's documented extent of cause was narrow, the team noted that the licensee planned actions to develop preventative maintenance strategies for FID-1 and FID-2 components besides relays and contacts as part of a broader action plan to address general equipment reliability at the facility. At the end of the inspection, the team noted that the licensee had closed the action item requiring the development of comprehensive preventative maintenance strategies for FID-1 and FID-2 contacts as provided in CR 20070725, Action Item 42. The team observed that although the action item was closed that the licensee was still revising and refining the strategies at the end of the inspection. The team concluded that the licensee was still developing adequate preventative maintenance strategies for FID-1 and FID-2 relays and contacts.

As a result of: (1) the inadequate assessment of the potential failure mechanism of binding or sticking of auxiliary contact actuators due to inappropriate application of wet lubricants; (2) the untimely actions associated with the extent of condition to FID-2 relays and contacts; and (3) as a result of the on-going development and refinement of your preventative maintenance strategies for relays and contacts to assure adequate maintenance in the future, NOV 05000285/2007011-03 will remain open. Consequently, the NRC will inspect the licensee's actions to address these concerns at a date to be determined. The team considered that successful closure of this NOV depended on: (1) an adequate assessment of contactor assembly mechanical binding due to the past application of Molykote 55M; (2) development of an adequate plan, if needed, to address any generic concern of contactor mechanical binding; (3) successful closure of URI 05000285/2008006-01; and (4) satisfactory development of preventative maintenance strategies to conduct maintenance on FID-1 and FID-2 relays and contactors including a successful demonstration of application of those strategies.

RCE 2007-0756, EDG-1 Unknown Inoperability

The licensee's evaluation of extent of condition concluded that, because of inadequate PMT, other safety-related equipment was potentially inoperable without the knowledge of responsible personnel. The team noted that CR 200700756, Action Item 41, provided that a review of the corrective action program database should be conducted to determine whether other equipment had been found inoperable and whether such inoperability was due to an inadequate PMT. Furthermore, discussions with the licensee regarding this item indicated that potential inoperability issues would reveal themselves during surveillance testing.

The team concurred with the licensee's assessment of extent of condition. However, the team considered the action item itself inappropriate because it relied on an audit of the CR system to identify latent operability issues. Such effort would only identify problems that had been corrected, not undiscovered operability issues. Further, the team considered the licensee's reliance on self-identification of inoperable conditions inadequate. Although some equipment may be self-revealed through the surveillance testing process, such process would not necessarily identify latent equipment operability issues. Additionally, the completion date for this item was set for June 30, 2008, beyond a reasonable resolution period, considering the time of discovery, February 16, 2007. The team concluded that a licensee assessment of work orders with questionable or inadequate PMT would adequately have addressed the extent of condition and either provided assurance that the components were in fact operable or revealed that they needed additional postmaintenance testing to demonstrate operability. The licensee documented the team's observation in CR 200801712.

In addressing extent of cause, the licensee concluded that: (1) other work orders may exist that are in a "ready" status, but have inadequate PMT requirements; and (2) a culture exists at the station that accepts, endorses, and rewards behaviors that sometimes lead to mediocre or adverse results.

The team concluded that both examples of extent of cause were inadequate. The team considered the first example to be a variation of the extent of condition conclusions.

Specifically, the stated extent of cause would simply identify pending work orders that have inadequate PMT requirements, in essence, preventing future extent of condition concerns. The team noted that the root cause, as determined by the licensee, was a process that lacked specific guidance and was over-reliant on skills and knowledge of planners and engineers. Therefore, the team concluded that an appropriate extent of cause evaluation should have considered other station processes that, like the PMT process, potentially lacked proper guidance or relied on the knowledge and expertise of personnel implementing the process. Regarding the licensee's second conclusion of extent of cause being attributable to a station culture aspect, the team considered the licensee's conclusion to be more representative of a contributor to the root cause and not representative of extent of cause.

The team noted that the licensee had broad action items to improve the adequacy of the PMT program with respect to over-reliance on work planner and engineering skills and knowledge, as provided in the action plan of the station focus area of Equipment Reliability. These actions were acceptable.

(3) SSFF PI

LER 2006-002

The licensee examined the potential for nonsafety grade 120 VAC power to supply safety grade instrument loops. That review did identify a population of safety-related loads supplied by nonsafety 120 VAC power. These interfaces were dispositioned because some of these cross connections fed isolators for redundant nonsafety indication or annunciators not required for accident mitigation. However, the extent of condition review for CR 200602855, Action Item 3, identified three instruments (AFW Flow Transmitters FT-1109 and FT-1110 and Emergency Feed Water Storage Tank Level Indicator LIA-1188) that were safety related but were supplied by nonsafety grade power. The licensee concluded that this did not affect operability of the components. The team noted that a design basis document provided that these instruments were required to be supplied by class IE safety power. After further review of NUREG 0737, "Clarification of TMI Action Plan Requirements," the licensee concluded that the design basis document was incorrect and that nonsafety grade power was acceptable. CR 200801720 was initiated to document the issue and update the design basis document.

LER 2006-003

For the inoperable containment air coolers, the licensee's extent of cause review consisted of a quality assurance audit, conducted in 2006, of the station's database system used for tracking action requests. The results determined that there were several action requests that were not being tracked appropriately. However, the assessment concluded that the audit did not require the auditors to ascertain whether or not any tracked action requests should have also been included in the corrective action program. The licensee conducted a second review of tracked action requests and did not identify any concerns with items that were required to also be tracked in the corrective action process.

The licensee conducted a review of CRs to determine whether any had been revised due to initially inadequate operability evaluations. The licensee identified 12 CRs that were identified as having incorrect operability evaluations when first evaluated, but did not exceed the applicable technical specification allowed outage time. The licensee considered this review as an internal OE review to identify potential precursors for identifying problems with operability evaluations that were incorrect due to faulty assumptions or information. However, the team considered that this review was representative of extent of condition. Specifically, the issue resulted in an inadequate operability evaluation as a result of inadequate design basis document information.

The team did not identify any other concerns with the licensee's assessment of extent of condition or extent of cause.

LER 2006-008

Regarding the loss of shutdown cooling, the licensee's extent of condition focused on the effects of running the low pressure safety injection pumps without sufficient recirculation for three minutes and the affects on the pumps. The licensee concluded that no pump degradation occurred. The team found that, although this is an important aspect, this equipment review was not representative of an extent of condition, but instead belonged in the risk assessment portion of the root cause to support availability of the pumps.

The licensee's extent of cause evaluation provided that other operating procedures and instructions may exist that omit vital information (i.e., caution statement) prior to performing a critical step with tight operating parameters by which to operate. The team questioned if any EOPs or abnormal operating procedures (AOPs) were revised to include a caution or guidance for using pressurizer heaters with sufficient spray similar to the revision that was made to Operating Procedure OP-3A. The team reviewed Procedure EOP 2, "Loss of Off-Site Power Loss of Forced Circulation," Revision 16, and noted that without offsite power and reactor coolant pumps, auxiliary pressurizer spray and heaters powered from the vital buses are utilized for reactor coolant system pressure control during cooldown until placing shutdown cooling in service. Procedure EOP-2 directs the reactor operators to EOP/AOP Attachment 2, "RCS Pressure-Temperature Limits for 40 EFPY [Effective Full Power Years]" for cooldown rate and EOP/AOP Attachment 4, "SDC Without RAS [Recirculation Actuation Signal]." Attachment 4 directs the reactor operator to utilize auxiliary spray and heaters to maintain reactor coolant system pressure and pressurizer level during natural circulation cooldown and while placing SDC in service. When asked by the team if these procedures needed additional guidance or cautions similar to OP-3A, the licensee provided that revisions to the EOPs and AOPs were not necessary because engineered safety features de-energize the pressurizer heaters and that only OP-3A needed such guidance for reactivity control. The team concluded that considering that the licensee conducted training on the revision to OP-3A and on coordination of the use of pressurizer heaters and sprays without reactor coolant pump operation, that a specific procedure revision to the EOP's and AOP's was not necessary.

LER 2007-004

For the inadvertent isolation of containment spray, the licensee concluded that an extent of condition potentially exists in the containment spray system or other systems with cross-train interlocks to have incomplete procedural guidance to ensure that the minimum required conditions for operability are met during testing. The licensee noted that there were three previous concerns associated with potential deficiencies in the design change associated with the containment spray system. One of these concerns was documented in CR 200601606, written to evaluate the potential for a pump runout condition on the containment spray system due to a single active failure of the electrical system. The licensee credited CR 200601606, Action Item 3, for the extent of condition review associated with CR 200701647, which consisted of evaluating risk significant systems for cross-train dependencies.

The licensee's extent of cause was that past design changes may not have been assessed for the impact on system operability during surveillance testing and design basis accident design requirements, and as a result that surveillance tests for other systems may inadvertently render the system inoperable without operator knowledge. The licensee conducted a review of the same systems evaluated in the extent of condition assessment to verify the adequacy of the surveillance tests to assure that systems were not rendered inoperable considering design basis accident design requirements. No issues were identified by the licensee. The licensee also reviewed Design Change MR-FC-90-053 that implemented the cross-train dependency on the containment spray system. The licensee noted no additional issues with the design change.

The team concluded that the licensee's extent of condition assessment was inadequate because it was limited to electrical cross-train dependencies of the design of the systems evaluated and did not assess mechanical dependencies and design requirements of the systems. Additionally, although the licensee conducted an additional review of Design Change MR-FC-90-053 and did not find any deficiencies, the team identified a potential deficiency with containment spray pump runout due to a single active mechanical failure (See Section 02.04(3), "LER 2007-004," for more details)

02.03 <u>Corrective Actions</u>

a. Determine that the appropriate corrective action(s) are specified for each root/contributing cause or that there is an evaluation that no actions are necessary.

(1) <u>Inadequate Maintenance and PMT of HCV-345</u>

The licensee developed 34 corrective actions to correct the problem and prevent recurrence. The licensee's corrective actions focused on:

- Correcting the procedure flexibility that caused maintenance personnel to incorrectly repair the containment spray isolation valve
- Creating a robust PMT for the containment spray isolation valve
- Correcting training curricula, including procurement of a valve mockup, to improve the knowledge of the maintenance personnel
- Identifying and correcting procedures that contain the procedure flexibility similar to the procedure for the containment spray valve

- Identifying and correcting PMT program requirements and associated procedures that deviate from industry standards

- Effectiveness reviews to monitor the implementation of corrective actions
The team concluded that the licensee's corrective actions were adequate to prevent recurrence of the root and contributing causes.

(2) Inadequate Maintenance Procedure and Corrective Actions for EDG-1 Relay Failure

RCE 2007-0725, EDG-1 Field Flash Functional Failure

The licensee determined that one of the contributing causes for the EDG-1 field flash functional failure was inappropriate application of wet lubricant to the 2CR relay auxiliary contacts. The team reviewed one of the corrective actions related to this contributing cause to revise Procedure EM-PX-1100, "480 Volt Motor Control Center Maintenance," Revision 18, on August 28, 2007, to specifically remove steps directing application of Molykote 55M to the relays auxiliary contacts slider. However, during a review of requested maintenance documents, the team identified that a second maintenance Procedure EM-PX-1102, "480 Volt Motor Control Center Cubicle Maintenance," Revision 3, was not revised although it contained a similar direction to apply Molykote 55M. The licensee indicated that the last time this procedure was used was in 2002 and only used during outages. The team concluded that the station did not conduct an adequate review with respect to identifying other inadequate maintenance procedures that directed the application of Molykote 55M. The team also concluded that the licensee had failed to implement adequate corrective actions regarding this contributing cause. The licensee indicated that, during a review of the documents provided to the team prior to the team's arrival on site, they had identified that Procedure EM-PX-1102 was deficient in that it included directions to apply Molykote 55M and had, therefore, initiated actions to remove the step. The licensee conceded that the deficient procedure was not identified in a timely manner and was only identified because of the earlier NRC document request. Additionally, the licensee provided that although the deficient procedure was identified, that a CR was not initiated at the time of discovery. The licensee documented the concern with the deficient procedure and the failure to document the concern in CR's 200801518 and 200801539, respectively. 10 CFR Part 50, Appendix B, Criterion V, "Instruction, Procedures, and Drawing," required in part that activities affecting quality shall be prescribed by procedures appropriate to circumstances. Contrary to this requirement, Procedure EM-PX-1102, a safety-related procedure, was deficient in that it directed the application of Molykote 55M on motor control center cubicle starter contactor sliders. However, the finding was determined to be of minor risk significance because no actual failures or degradation of motor control center cubicles starter contactors had been attributed to the application of Molykote 55M.

The team also noted that at the time of the inspection that the licensee was still making refinements to the overall preventative maintenance strategy to implement adequate maintenance on the relays and contactors. Therefore, it was not clear that the licensee had fully developed the preventative maintenance strategies that would assure that all of the correct maintenance would be implemented.

The team concluded that the corrective actions identified by the licensee were, in general, adequate to address the root and other contributing causes. The team also noted that the licensee established effectiveness measures to monitor the adequacy of the developed corrective action plan.

RCE 2007-0756, EDG-1 Unknown Inoperability

The licensee implemented corrective actions to address the root and contributing causes. Examples include: (1) developing a PMT matrix to support maintenance planners and system engineers in the development of adequate PMT; (2) revisions to maintenance planning guidance documents; (3) training on the use of the revised guidance documents and PMT matrix; and (4) benchmarking of other nuclear facilities to identify best practices regarding PMT development. The team also noted that the licensee planned to implement a design change to eliminate the failure mechanism of Relay 2CR contacts sticking open that caused the EDG-1 failure on February 16, 2007. The team concluded that the corrective actions for the licensee's identified root and contributing causes were, in general, adequate to address the root and contributing causes.

However, as noted in Section 02.02.d(2) addressing RCE 2007-0756, the team concluded that the licensee failed to appropriately identify the extent of cause. Specifically, that other station processes may have weak guidance or may be over reliant on skills and knowledge of the individuals implementing the process. Therefore, there were no specific corrective actions provided in CR 20070756 to address this extent of cause. The team determined, however, that the licensee had broader corrective actions identified in the station focus area action plans which did address the extent of cause. Specifically, under the focus area of Problem Identification and Resolution, the licensee had plans to benchmark and revise the station's corrective action program due to a weakly documented process. Additionally, the licensee identified weak processes in the area of engineering design change. The licensee plans to revise and strengthen these processes through the station focus area of Latent Engineering Issues. The team considered these other actions sufficient to address the extent of cause associated with a weak PMT process.

(3) SSFF PI

LER 2006-002

To address the nonsafety-related auxiliary feedwater power supply, root cause of inadequate engineering procedures, the licensee updated Procedure PED-QP-3, "Calculation Preparation, Review and Approval", to require engineers to identify if other engineering disciplines are affected and if not, to justify why such a review is not needed. The licensee also reviewed, as an enhancement, Procedures PED-GEI-3, "Preparation of Modifications," Revision 51, and PED-GEI-29, "Preparation of Facility Changes," Revision 27, and found that no additional reviews were necessary as the procedures already provided the necessary multi-discipline reviews.

The team did not identify any specific corrective actions in the CR to address the extent of condition. However, the team noted that CR 200602855, Action Item 5, due on January 11, 2008, specified that engineering should review vendor performed calculations for the last 12 months with verification that multidiscipline reviews were conducted. This action was specified as an effectiveness review, but the team determined that this was more closely related to extent of condition. Action Item 5 was then closed to Action Item 22, which also directed an effectiveness review to audit calculations but allowed surveying of engineers to determine if they understood the new requirements for multidiscipline reviews. Action Item 22 was due March 2009.

Additionally, the team could not identify corrective actions under CR 200602855 to address the time pressure aspects that contributed to the 1997 flawed operability evaluation which was a contributing cause. However, the team noted that CR 200702699, written to assess the licensee's placement in the degraded cornerstone column of the NRC's action matrix, Action Item 21, resulted in a revision to Procedure PED-QP-2, "Configuration Change Control." This revision was made to ensure that time pressures did not negatively impact the rigor and quality of configuration changes, plant status or critical design decisions.

The team verified that the licensee corrected the equipment problems by implementing an engineering change package to provide safety grade 120VAC power to the control loop for Valve FCV-1368. The team also verified that a change was made to place the instrument loops for Valves FCV-1368 and FCV-1369 (recirculation for turbine driven AFW) back on the Critical Quality Equipment List. Additionally, the team verified that the increased SG pressure was reflected in the flow rate calculation for the steam driven AFW pump. No other significant comments or observations were noted by the team.

<u>LER 2006-003</u>

For the inoperable containment air coolers, the licensee completed an analysis to determine the 24-hour mission time basis and updated an associated design basis document, updated safety analysis report, and technical data book, for requirements on valve position, mission time, and acceptable nitrogen leakage rate to assure operability. A quarterly surveillance was added to check the 400 series valves nitrogen accumulators' leak rate. Procedure AOP 17, "Loss of Instrument Air," Revision 11, was issued to reflect failure positions on 400 series valves. The licensee also conducted training on how to perform operability evaluations.

The team identified one corrective action that was inappropriately revised. Specifically, RCE 200603765, recommended a corrective action to incorporate pneumatic leakage requirements into test Procedures OP-ST-CCW-3005A and OP-ST-CCW-3005B. These procedures provided, in part, the surveillance test requirements for the series 400 component cooling water valves. However, the associated CR 200603808, Action Item 17, directed issuance of a new Procedure IC-ST-IA-3010, "Accumulator, Check Valve and Trip Valve Testing for The "400 Series" Containment Fan Cooler Inlet and Outlet Valves," Revision 0, which incorporated the leakage requirements instead. The licensee determined that this corrective action was changed without permission from the plant review committee. CR 200801464 was written to document the inappropriate revision of the corrective action.

The team requested the setpoint for the regulators in the '4A' style in Drawing C-4175, Sheet 1. The licensee subsequently discovered while reviewing the basis for the '4A' style regulator setpoint that for the 'E' style regulators, there was no formally accepted calculation. The licensee did identify an unreviewed vendor calculation that had been used to set the regulators at 50 psig nominal. The licensee initiated CR 200801948 and subsequently confirmed the adequacy of the setpoint by verifying the actuator capability utilizing the 50 psig regulator setpoint with a computer analysis designed to assess AOV capabilities and successful surveillance test stroke times for the 400 series valves utilizing the 50 psig setpoint. The team noted no other issues or concerns.

LER 2006-008

For the loss of shutdown cooling event, the licensee's corrective actions to address the root cause of a failure to apply adequate operator fundamentals included licensed operator requalification training and just-in-time training. The training emphasized the need to initiate auxiliary spray, minimize heat input, and apply sound operator fundamentals. Procedure OP-3A, "Plant Shutdown," Revision 67, was also revised to caution operators of the loss of spray when all reactor coolant pumps are stopped to address one of the licensee's identified contributing causes. The licensee also revised Procedure OPD-3-10, "Minimizing Control Room Distractions Performance Standard," Revision 6, to provide additional guidance regarding additional supervisory and management oversight of critical evolutions and during periods of high work load. The licensee also provided corrective actions associated with improving supervisor oversight of key activities, in general for the station, in CR 200701020, Action Items 32-34.

The team determined that the licensee's actions to address the root and contributing causes to be adequate.

LER 2007-004

The licensee implemented corrective actions to revise the containment spray surveillance procedures on April 12, 2007, to assure that operability would be appropriately controlled. Additionally, the licensee revised Procedure PED-GEI-3, "Preparation of Modifications," to assure that plant modifications appropriately considered design basis accident requirements during surveillance tests. Procedure PED-GEI-3 will also be revised to require PMT to ensure systems are operable per Technical Specifications. Procedure SO-G-21, "Modification Control," was changed to require independent review and evaluation of operability during testing for modifications. The licensee also conducted training with engineering personnel regarding the event and actions that were taken to prevent recurrence.

The team determined that the actions were appropriate to address the root and contributing causes.

b. Determine that the corrective actions have been prioritized with the consideration of the risk significance and regulatory compliance.

(1) Inadequate Maintenance and PMT of Valve HCV-345

The licensee did not prioritize their corrective actions based on risk significance. However, the licensee did take immediate actions to correct the incorrect valve alignment and comply with technical specification requirements at discovery. The licensee ranked the priority of the corrective actions based on the type of corrective action. The corrective action types were: (1) correct the problem (2) prevent recurrence (3) long term action (4) effectiveness reviews and (5) enhancement. The correct actions specified as type (1) and (2) were given shorter periods of time, 0-30 days, for completion than the actions specified as Types (3), (4), and (5).

The team concluded that although the licensee did not prioritize corrective actions specifically with regard to risk significance, the prioritization that was considered was determined to be adequate to assure timely completion of the actions which directly addressed correcting and preventing recurrence of the problem.

(2) Inadequate Maintenance Procedure and Corrective Actions for EDG-1 Relay Failure

RCE 2007-0725, EDG-1 Field Flash Functional Failure

The team's review of the scheduled completion of the corrective actions identified in CR 20070725 concluded that, in general, the action items had been adequately prioritized. As indicated previously, however, the actions to address extent of condition were less than timely in that they failed to recognize the potential existence of common cause failures, due to inadequate lubrication activities, that potentially could have rendered multiple safety-related circuits and systems unavailable when called upon to perform their intended safety function. Therefore, the licensee's schedule for verifying the operability status of important components was not realistic and not reflective of the safety concerns associated with such potential failures.

RCE 2007-0756, EDG-1 Unknown Inoperability

The team's review of the completed and scheduled corrective actions concluded that, in general, the corrective actions were adequately prioritized. However, as discussed in Section 02.02.d(2), one action item associated with extent of condition was not adequate and untimely. Specifically, CR 20070756, Action Item 41, relied on an audit of the CR system to identify latent operability issues. The team concluded that this would only identify problems that had been corrected and would not identify latent operability issues. Further, the team considered the licensee's reliance on self-identification of inoperable conditions less than proactive. Although some equipment may be self-revealed through the surveillance testing process, such process would not necessarily identify latent equipment operability issues. Additionally, the completion date for this item was set for June 30, 2008, well beyond a reasonable resolution period, considering the time of discovery, February 16, 2007, and the potential implications, if inoperable equipment existed in the plant without licensee personnel knowledge. The licensee documented the team's observation in CR 200801712.

(3) SSFF PI

LER 2006-002

For the nonsafety-related auxiliary feedwater instrument power supply, CR 200602855, Action Item 21, directed a design review of pumps with credited accident mitigating functions to assure that the design inputs for pump performance reflect appropriate design basis parameters, and that recirculation valves and support components have the correct safety classification to ensure valve functions as required to fulfill the safety function. The action was credited as an extent of condition assessment and was scheduled for completion by June 27, 2008. Although the team considered Action Item 21 to be appropriate, the team considered that given the original identification of the issue in 2006, that a June 27, 2008, due date was an excessive period of time to complete an extent of condition assessment.

The team did not identify any other issues or concerns with prioritization of the corrective actions.

LER 2006-003

For the inoperable containment air coolers, the team concluded that nearly all of the licensee's identified corrective actions are completed. Those that have been complete and those that are still open were adequately prioritized with respect to the risk significance of the issue and regulatory compliance.

LER 2006-008

For the loss of shutdown cooling event, the team determined that the corrective actions were prioritized according to their safety significance and the next planned refueling outage. The training of operating crews on this particular scenario has been completed as well as the procedural changes discussed earlier in this report.

LER 2007-004

For the inadvertent isolation of containment spray event, the team concluded that nearly all of the licensee's identified corrective actions are complete. Those that have been complete and those that are still open were adequately prioritized commensurate with the risk significance of the issue and regulatory compliance.

c. Determine that a schedule has been established for implementing and completing the corrective actions.

(1) Inadequate Maintenance and PMT of HCV-345

The licensee established an appropriate schedule to correct and prevent recurrence of the root and contributing causes. The licensee ranked the priority of the corrective actions based on the type of corrective action. The corrective action types were: (1) correct the problem (2) prevent recurrence (3) long term action (4) effectiveness reviews and (5) enhancement. The correct actions specified as types (1) and (2) were given shorter periods of time, 0-30 days, for completion than the actions specified as types (3), (4), and (5).

The team concluded that the licensee's schedule for implementing and completing the corrective actions was appropriate.

(2) Inadequate Maintenance Procedure and Corrective Actions for EDG-1 Relay Failure

RCE 2007-0725, EDG-1 Field Flash Functional Failure

The team reviewed the action items in CR 20070725 and confirmed that a schedule was established for the development, completion, and implementation of the corrective actions identified for each action item. Except for the corrective actions related to extent of condition and extent of cause described earlier in this report, and also in consideration of the revisions made by the licensee to the root cause analysis, the team concluded that the scheduled completion of the various action items were reasonable. The team also confirmed that the immediate corrective actions other action items scheduled for completion prior to the team inspection were completed.

RCE 2007-0756, EDG-1 Unknown Inoperability

The team reviewed the action items in CR 20070756 and confirmed that a schedule was established for the development, completion, and implementation for each of the actions. The team concluded that the scheduled completion of the various action items was reasonable with the exception of Action Item 41 as discussed previously in this report. The team confirmed that the immediate corrective actions and other action items scheduled for completion prior to the team inspection were completed.

(3) SSFF PI

LER 2006-002

The team noted that at the time of the inspection, most corrective actions identified in CR 200602855 had been completed. The team found that the direct causes were promptly corrected. During interviews, the team noted that the Engineering Focus area and the resources this focus area required dictated the schedule of completion of the remaining actions. As such, the licensee planned for completion by contracting additional engineering expertise. Those contracts specified the types of calculation and design reviews needed.

LER 2006-003

For the nonsafety-related power supply, most corrective actions specified in CR 200603808 had been completed, with the exception of Action Items 35, 36, and 37, which were all effectiveness reviews and were appropriately scheduled. The team found that the direct causes were promptly corrected and that the timeliness of updating the design basis documents, USAR, and surveillance procedures for the 400 series valves was timely.

LER 2006-008

For the loss of shutdown cooling event, most corrective actions were completed with the exception of several effectiveness review action items that were appropriately scheduled. The team noted that corrective actions were generally corrected according to their safety significance and the next planned refueling outage. The training of operating crews on this event has been completed as well as the required procedure changes.

LER 2007-004

For the inadvertent isolation of containment spray event, most corrective actions were completed. However, completion of CR 200701647, Action Item 10, a revision of Procedure PED-GEI-3 "Preparation of Modifications," by March 28, 2008, was the most direct for preventing recurrence. Given the period between the identification of the issue in 2006 and the revision to this procedure, there was additional exposure to inadequate reviews of modifications. However, the team did not identify any other additional inadequate modification reviews. Additionally, the licensee conducted training with engineering staff on the causes leading to this LER. Some enhancement action items remain to be completed such as evaluating the need to change or remove the containment spray header valve logic.

d. Determine that the quantitative or qualitative measures of success have been developed for determining the effectiveness of the corrective actions to prevent recurrence.

(1) Inadequate Maintenance and PMT of HCV-345

The licensee identified corrective actions to conduct effectiveness reviews which were scheduled for completion three to twelve months from the date the corrective action was closed. For example, the licensee will track equipment failures for the containment spray isolation valves due to inadequate performance of the procedure or inadequate PMT. The licensee will review this measure in July 2008 and December 2009.

The team concluded that the licensee's effectiveness reviews for the implementation of the corrective actions were adequate.

(2) Inadequate Maintenance Procedure and Corrective Actions for EDG-1 Relay Failure

RCE 2007-0725, EDG-1 Field Flash Functional Failure

The team concluded that action items to evaluate the effectiveness of the corrective actions and to make appropriate adjustments, if necessary, were appropriately identified and planned by the licensee. For instance, CR 20070725, Action Item 20, required that the licensee verify that there are no functional failures of DG-1 and DG-2 control circuits caused by high resistance CR105 auxiliary contact in the next two years. Also, Action Item 21 required that the effectiveness review of Action Item 20 be extended to the EROP strategic initiative FID-1 and FID-2 CR-105 contacts. Lastly, Action Items 49, 50 and 51, required a review of corrective maintenance work orders for failures associated with high contact resistance for FID-1 and FID-2 contacts and to adjust corrective actions as appropriate.

RCE 2007-0756, EDG-1 Unknown Inoperability

The team concluded that action items to evaluate the effectiveness of the corrective actions and to make appropriate adjustments, if necessary, were appropriately identified and planned by the licensee. For instance, Action Items 4, 16 and 17 required that the managers of system engineering and work management conduct a quarterly review of at least 50 completed work documents to ensure that PMT requirements and completed PMT's meet their expectations. In addition, Action Items 43-46 required the monitoring of the success rate of the proper identification of PMT's by planners and system engineers by conducting pre-PMT implementation reviews by someone other than the planner or system engineer developing and approving the PMT.

(3) SSFF PI

LER 2006-002

Concerning the nonsafety-related auxiliary feedwater instrument power supply, the licensee planned to review effectiveness by performing multidiscipline reviews of vendor performed calculations over the last 12 months. As an alternative, if there were not a sufficient number of vendor calculations to review, the licensee would substitute interviews of design engineers to assure that they understood the requirements associated with multidiscipline reviews during the design change process by March 30, 2009. The team did not identify any concerns with the licensee's planned effectiveness reviews.

LER 2006-003

For the loss of containment air coolers, the licensee implemented a review of past operability evaluations that were potentially inadequate due to incorrect design basis document information. The effectiveness review audited operability evaluations that were documented between October 23, 2006, and June 28, 2007. The licensee identified no operability issues. The licensee also conducted a review of the action tracking database, Passport, to determine whether there were any action requests that should also be documented in the corrective action program but were not. Although there were several items identified that should have been documented in the corrective action program, the licensee determined that they were not operability affecting issues. The licensee plans to conduct a survey of plant employee's to assess the site's sensitivity to reporting and documenting issues at a low threshold.

The team considered the licensee's effectiveness reviews to be adequate.

LER 2006-008

For the loss of shutdown cooling event, the licensee's effectiveness review consisted of reviewing the upcoming 2008 refueling outage performance. Specifically, the criteria for success consisted of no loss of shutdown cooling events occurring due to operators failing to apply adequate fundamentals and that no Category A CRs be written due to a lack of operations supervisory oversight.

The team considered these measures of effectiveness to be too narrow. Specifically, events other than losses of shutdown cooling that occur due to a lack of operators applying adequate fundamentals should be considered. For example, reactivity events or loss of level control during shutdown would also represent significant events that could occur due to operators making mistakes. Additionally, the licensee's measurement of no 'Category A CRs would only have considered significant events that occurred due to inadequate supervisory oversight. However, lower level CR's such as Categories B or C would provide information regarding potential precursors to significant events due to inadequate supervisory oversight.

LER 2007-004

For the inadvertent isolation of containment spray, the licensee plans to perform quarterly reviews and trending of CRs to identify potential trends of incorrect assumptions, reliance on existing design, time pressure, and system complexity. The team considered the actions to be adequate.

02.04 Independent Assessment of Extent of Condition and Extent of Cause

Perform a focused inspection(s) to independently assess the validity of the licensee's conclusions regarding the extent of condition and extent of cause of the issues. The objective should be to independently sample performance, as necessary, to provide assurance that the licensee's evaluation regarding extent of condition and extent of cause is sufficiently comprehensive.

(1) Inadequate Maintenance and PMT of Valve HCV-345

The team reviewed site drawings and work orders to assess the potential of valve misalignment existing in other risk significant systems. Through this independent assessment, the inspectors concluded that the licensee's extent of condition was appropriate for the root cause analysis.

In addition, the team reviewed mechanical maintenance procedures and PMT for safety significant valves and pumps with a potential for incorrect assembly to assess the extent of cause. Specifically, maintenance activities associated with the EDGs and AFW were reviewed. The team did not identify any significant safety concerns.

(2) Inadequate Maintenance Procedure and Corrective Actions for EDG-1 Relay Failure

To address the root cause of the failed Relay 2CR, i.e., lack of preventive maintenance strategy for the relays, the team reviewed maintenance issues related to circuit breakers. Through discussions with responsible licensee personnel and applicable documentation, the team sampled maintenance activities and problem reports related to medium and low voltage circuit breakers. The team noted that some hardening of grease was observed in the medium as well as the low voltage circuit breakers. For instance, while rotating condensate pumps, the licensee experienced some anomalies with the Circuit Breaker FW-2B 4160 VAC circuit breaker (CR 200702580). These anomalies resulted in the breaker not fully closing and prevented the normal tripping of the breaker. A subsequent root cause analysis determined that a bushing associated with the cell mounted auxiliary switch, 52/STA, was missing. Additionally, an evaluation of the breaker operating mechanism found that some hardening of the lubrication had occurred. The licensee, in addressing these issues, provided that the observed lubrication hardening and the excessive plunger force and binding led to the stall condition that prevented the Breaker FW-2B from fully closing. Although this issue involved a non-safety-related component, hardening of the lubrication could potentially affect the operation of auxiliary switches in both safety and non-safety-related applications and therefore affect the correct operation of applicable circuits. The licensee is currently in the process of replacing the operating mechanism of the 4160 V breakers. However, the replacement extends until 2011 and beyond the recommended overhaul schedule (9 years) of the breakers. Regarding the specific breaker in question, the team's review also determined that the licensee had conducted preventive maintenance on the breaker only six month prior to its failure. The applicable preventative maintenance procedure specifically required that the breaker be inspected for damaged or missing parts and the operating mechanism lubrication points for contamination, oxidation (hardened or darkened) or missing lubricant. However, the missing bushing and hardened lubricant were not identified during the maintenance activity. The team did not identify any other concerns during the independent assessment.

(3) SSFF PI

LER 2006-002

The team reviewed Calculation FC 05361, "Auxiliary Feedwater System Calculation (Pump Design and Turbine Drive Controller)," Revision 6, to assess aspects of pump operation required for operability not previously identified. The team also reviewed the test data for the AFW pumps' recirculation flow rate to ensure that it was accurately incorporated into the calculation. Additionally, the team examined the AFW design basis documents for other errors and compared the assessment to the licensee's extent of condition review associated with other safety instruments fed by nonsafety power. The team identified that that the licensee's extent of condition did not address a discrepancy with the design basis document. Specifically, three instruments (AFW Flow Transmitters FT-1109 and FT-1110 and Emergency Feed Water Storage Tank Level Indicator LIA-1188) were safety related but were supplied by nonsafety grade power. The licensee concluded that the instruments were operable. The team noted that the AFW design basis document provided that these instruments were required to be supplied by Class IE safety power. After further review of NUREG 0737, "Clarification of TMI Action Plan Requirements," the licensee concluded that the design basis document was incorrect and that non-safety grade power was acceptable. The licensee documented the issue in CR 200801720. The team did not identify any other errors with the design basis document.

LER 2006-003

For the loss of containment air cooler event, the team audited the licensee's action tracking database system, Passport, for issues to determine whether any equipment concerns existed that should have resulted in the initiation of a CR, but was not. The team also reviewed past operability evaluations to assess the adequacy of the assessment.

The team reviewed the testing of the 400 series valves for other design basis aspects and determined that the 400 series valves are not stroked during surveillances using their associated nitrogen backup supplies. The valves were stroke tested using non-safety related instrument air. However, the pressure supplied to the actuators, whether from the nitrogen backup or from instrument air, is the same due to the configuration of two regulators which adjust the pressure at the valve operator, regardless of the pressure source. The team therefore concluded that the stroke time testing of the valves would not be adversely affected by stroke testing with the instrument air source only. The licensee provided that a surveillance test is also conducted to ensure the valves and nitrogen supplies can support the mission time based solely on static leak rate test. However, the team determined that the test did not account for the design basis requirement of requiring the valve to be stroked an additional time following a containment isolation signal which utilize more nitrogen as provided in Design Basis Document SDBD-AC-CCW-100, "Component Cooling Water," Revision 41, Attachment 16. The team did not identify any leak rate surveillance tests which may have failed if additional nitrogen was used for the additional valve stroke. The licensee documented the deficiency in CR 200801822. During a review of the design requirements for the pressure regulators associated with the 400 series valves, the team identified that for the 'E' style regulators, that there was not a formally accepted calculation to establish the regulator setpoints. The licensee determined that an unreviewed vendor calculation had been used to set the regulators at 50 psig nominal. The licensee documented the issue in CR 200801948. The licensee confirmed that the informally established setpoint was acceptable using a computer analysis that the licensee uses for safety-related AOV actuator capability. Furthermore, the 400 series valves have passed surveillance tests verifying stroke time and demonstrated adequate actuator capability.

LER 2006-008

For the loss of shutdown cooling event, the licensee's extent of cause evaluation provided that other operating procedures and instructions may exist that omit vital information (i.e., caution statement) prior to performing a critical step with tight operating parameters by which to operate. The team conducted an independent assessment of the extent of cause by reviewing other procedures that were similar to Procedure OP-3A in that they may not have precautions to assure that operators coordinate pressurizer spray and heaters accordingly during shutdown conditions. The team reviewed Procedure EOP-2, "Loss of Off-Site Power Loss of Forced Circulation," Revision 16, and noted that without offsite power and reactor coolant pumps, auxiliary pressurizer spray and heaters powered from the vital buses are utilized for reactor coolant system pressure control during cooldown until placing shutdown cooling in service. Procedure EOP-2 directs the reactor operators to EOP/AOP Attachment 2, "RCS Pressure-Temperature Limits for 40 EFPY [Effective Full Power Years]" for cooldown rate and EOP/AOP Attachment 4, "SDC Without RAS [Recirculation Actuation Signal]." Attachment 4 directs the reactor operator to utilize auxiliary spray and heaters to maintain RCS pressure and pressurizer level during natural circulation cooldown and while placing SDC in service. When asked by the team if these procedures needed additional guidance or cautions similar to Procedure OP-3A, the licensee provided that revisions to the EOPs and AOPs were not necessary because engineered safety features de-energize the pressurizer heaters and that only Procedure OP-3A needed such guidance for reactivity control. The team concluded that considering that the licensee conducted training on the revision to Procedure OP-3A and on coordination of the use of pressurizer heaters and sprays without reactor coolant pump operation, that a specific procedure revision to the EOP's and AOP's was not necessary.

LER 2007-004

The team conducted an independent review of the design of the containment spray system as it related to the design change that removed the auto-start feature of Pump SI-3C and the cross-divisional design aspects of the other pumps and spray header isolation valves. In particular, the team evaluated the potential for common cause or single active failure scenarios that could render containment spray inoperable. While the licensee limited its reviews of the containment spray modification to electrical aspects, the team assessed both electrical and mechanical design considerations. The team identified an URI as discussed in more detail in Section 02.06, Other Activities, "Containment Cooling Design Concern," of this report. The team also reviewed 480 VAC drawings to determine if there were other system dependencies that could cause failure of one of the containment spray header AOV's to close on demand. The inspectors did not find any other design deficiencies.

02.05 Safety Culture Consideration

The team conducted an independent assessment of whether the licensee's root cause and common cause evaluations appropriately considered whether any safety culture component caused or significantly contributed to any risk significant performance issue. The team reviewed the most recent safety culture survey and independently assessed for applicability each of the safety culture components listed in NRC Inspection Manual Chapter (IMC) 0305, "Operating Reactor Assessment Program," to determine if one or more of the components could have reasonably been a root cause or significant contributing cause to the respective events analyzed. The team also interviewed plant personnel to obtain staff opinions regarding the current safety culture at Fort Calhoun Station.

Utilities Service Alliance Safety Culture Survey

The team reviewed the results of the most recent safety culture survey performed in January 2007 in association with the Utilities Service Alliance. The team determined that the safety culture work environment at Fort Calhoun Station appeared healthy, as most staff indicated that they would not be hesitant to raise safety concerns. However, the survey also revealed some weaknesses in plant procedures and in human performance, specifically in the willingness of plant personnel to question plant conditions and procedures in the event of uncertainty. These weaknesses were also affirmed during interviews of the plant staff.

The team noted that at the time of the inspection that the licensee had no documented plans to conduct a comprehensive safety culture survey prior to September 2009. The inspectors considered that the external oversight provided by a comprehensive safety culture survey would be a great asset to the station's performance improvement plan. The licensee indicated that their performance improvement plan would be revised to include a comprehensive safety culture survey during calendar year 2008.

Root Cause and Common Cause Evaluations

The team reviewed the safety culture aspects of the RCEs performed for the individual White findings and common cause analysis that collectively evaluated the SSFF PI and other licensee identified issues:

Inadequate Maintenance and PMT of HCV-345:

The team generally concurred with the licensee's safety culture analysis as documented in CR 200604627 "Faulty Maintenance Renders One Train of Containment Spray Inoperable." However, the team noted that the safety culture component in human performance regarding conservative assumptions [H.1.b] was not flagged as applicable for this event. In reviewing the sequence of events, the team determined that licensee personnel made the false assumption that replacing a containment spray check valve while it was connected to its associated packing box would automatically result in the check valve being installed in the correct position. The team concluded that this false assumption significantly contributed to the improper check valve installation. The licensee concurred and indicated that the conservative assumptions component would be incorporated in their performance improvement plan. The licensee documented the concern in CR 200801523.

Inadequate Maintenance Procedure and Corrective Actions for EDG-1 Relay Failure

The team considered the licensee's safety culture analysis documented in CRs 200700725 and 200700756 thorough, as it adequately captured six different safety culture components in human performance as well as problem identification and resolution.

SSFF PI

The licensee conducted a common cause analysis to assess the collective root causes, common causes, and lower level causal factors, which contributed to the individual issues of the White SSFF PI as well as consideration for the station's current substantive crosscutting aspect in human performance and placement in Column 3 of the NRC action matrix. The licensee documented the analysis in CR 200701704. The team noted that the licensee utilized 21 inputs consisting of RCEs, external organizations' reports, common cause analyses, and safety culture assessments as inputs into this common cause analysis to address specific areas for corrective action. The licensee utilized a 'why staircase' to establish general focus areas and the root, apparent and contributing causes and additional important causal factors. The licensee also applied the NRC's safety culture areas and components to each of the causal factors to all issues and identified 14 crosscutting aspects in Human Performance, Problem Identification and Resolution, and Safety Culture. "Performance Improvement International," (a vendor supplied technique which the licensee utilized to identify failures in department-to-department interactions, programmatic deficiencies, and department-to-program deficiencies) and cognitive trending (the grouping of like causes) were used on the other root causes to identify the focus area needed to address the causes of the overall station problems. The team noted that the licensee appropriately identified safety culture aspects of human performance problems in decision-making, resources, and work practices. There were also identified weaknesses in problem identification and resolution in the corrective action program as well as in incorporating the use of OE and self-assessments to prevent plant problems. The licensee also considered that other safety culture components of accountability and organizational change management also contributed to the individual equipment issues. The team concluded that the licensee effectively identified all of the safety culture components that contributed to the issues that were assessed. The inspectors considered the identified safety culture components to be significant and substantial contributors to the equipment and performance issues that resulted in Fort Calhoun Station being placed in the Degraded Cornerstone Column of the NRC Action Matrix. As a result the common cause analysis, the licensee identified the five following focus areas:

- Latent Engineering Issues
- Equipment Reliability
- Human Performance

- Problem Identification and Resolution
- Station Culture

The team reviewed associated action plans for each of the focus areas and considered the plans adequate, if implemented as scheduled and documented, to improve performance at the station.

Staff Interviews

The inspectors interviewed 24 individuals from a cross section of plant staff regarding site safety culture. The interviews consisted of personnel, chosen at random, from the security, operations, maintenance, engineering, radiation protection, and training departments.

The individuals interviewed were generally in consensus that real performance problems have developed at Fort Calhoun Station over a relatively long period of time, from two to five years, with some individuals indicating problems have been evolving for as long as ten years. Most personnel indicated that past plant management had not interfaced well with site staff, but were enthusiastic with the current management team in place. Most personnel also indicated that they believed the performance improvement plan would be effective in restoring proper safety culture to the site. All personnel interviewed indicated that they were willing to raise safety concerns, and would not hesitate to pursue the employee concerns program if their individual safety concerns were not satisfied.

However, the majority of personnel interviewed indicated that they felt individuals were not held accountable for their performance and that there was a tendency to blame programs or procedures rather than individuals when personal performance issues surfaced. In addition, most individuals indicated that more focus needed to be placed on equipment aging issues, as well as updating plant procedures to make them more effective in identifying and emphasizing critical steps. Most individuals also indicated that there was a need to ensure plant staffing was augmented to ensure an adequate turnover of plant specific knowledge from employees near retirement to the new generation of employees that will operate the plant in the future. Most individuals also indicated that they were hopeful that their management would be proactive in emphasizing the need to have a questioning attitude when faced with uncertainty while performing plant activities.

02.06 Other Activities

Team Review of Other LER's for Impact on SSFF PI

The team reviewed six LER's determined by the licensee not to affect the SSFF PI, including LER 2006-007, "Inadequate Seismic Design of Reactor Vessel Head Refueling Stand," which was originally reported by the licensee as a SSFF but was later retracted. The team also reviewed 25 CRs that the licensee initially screened as potentially reportable between May 2006 and February 2008. The team did not find any issues that should have been reported as LERs or any issues that were not properly counted against the SSFF PI. The team did note during review of LER 2006-001 that the licensee made a change to the Technical Specification Bases which was not consistent with the Technical Specifications. The bases may have allowed the licensee to enter the personnel airlock with one inoperable door for reasons other than to strictly repair the inoperable door. The team found no instances of such a practice. The licensee agreed to clarify the bases and documented this in CR 200801774.

The team reviewed operator log entries, corrective action documents, maintenance action item paperwork, maintenance rule data, and PI data sheets to determine whether the licensee adequately verified the PI. This number was compared to the number reported for the PI during the past three quarters. In addition, the inspectors interviewed licensee personnel responsible for compiling the information. The team did not identify any deficiencies and that the PI data is correct.

Team Review of Licensee's Assessment and Implementation of Corrective Actions to Address NRC PI Mitigating Systems (MS) PI (MSPI) – Emergency AC (EAC) Power Systems

The team reviewed the licensee's MSPI Basis Document for appropriate scoping and accumulation of unavailability time of those components within scope. The team did not find any incorrect scoping or application of unavailability time. The team also interviewed those responsible for increasing the availability and reliability of the EDGs. The licensee's internal metric on MSPI EAC was changed to use lower thresholds than the NRC. CR 200801335 was written on March 6, 2008, identifying several metrics exceeding thresholds, but the team did not identify any corrective actions other than those in the Equipment Reliability focus area. CR 200801264 was written to document that the licensee's internal EAC metric was yellow. The licensee indicated that preventative maintenance was being staggered across the two diesels to help mitigate the MSPI EAC and that additional maintenance personnel have been assigned during key maintenance windows to decrease inoperability and unavailability time.

Containment Cooling Design Concern

On March 17, 2008, during the inspection of LER 2007-004, "Inadvertent Isolation of Containment Spray due to Inadequate Test Procedure," the team postulated that a containment spray pump coupling failure, a pump discharge check valve failure to open, or a pump 480 VAC breaker mechanical failure could result in the inability of one pump to provide any containment spray flow. Consequently, the remaining operating pump would operate with both containment spray header isolation Valves HCV-344 and HCV-345, open resulting in a pump runout condition due to a single active mechanical failure.

The licensee identified a containment spray pump runout condition in 1990 in which both Valves HCV-344 and HCV-345 were open simultaneously with only one pump running would cause a runout condition and cause the motor to draw more amperage than the vendor allowable criteria of no more than 15 percent above its nameplate rating. The case of a single pump discharging to both spray headers would cause the motor to draw amperage 22 percent above its nameplate rating. After identifying this issue in 1990, the licensee planned to implement a piping modification to the spray header to prevent the runout condition, but elected instead to install additional valve opening logic which was intended to only allow one pump to operate with one spray header valve open or both pumps and both spray headers open. This modification was first installed between the B and C containment spray pumps, SI-3B and SI-3C, 480 VAC breakers and the Train A spray header isolation Valve HCV-344. This modification was also installed in 2006 between the A containment spray pump, SI-3A, and the Train B spray header isolation Valve HCV-345 as well as removing the auto start feature from the containment spray Pump C. Essentially, the modification consisted of an auxiliary contact being installed in each pumps' 480 VAC breaker cubicle which, when the breaker closed, would allow the opposite train's header isolation valve to open. After reviewing CRs 200601606, 200701647, 200701647, and LER 2007-004, the team found that the licensee's engineering reviews were focused on electrical aspects of single active failures resulting in pump runout and did not consider single active mechanical failure modes. The team noted that a previously submitted license amendment, License Amendment 235, which removed the automatic start feature to the containment spray Pump C also did not consider single active mechanical failures and the potential for pump runout. The license amendment addressed containment sump performance and net positive suction head concerns for the containment spray pumps.

The team concluded that the licensee's design changes as described above were potentially inadequate due to the failure to evaluate the potential of a single active mechanical failure, such as a pump coupling failure, resulting in pump runout on the remaining operating pump. The licensee subsequently developed an operability evaluation that credited existing operator actions in the EOPs to secure one of the two running containment spray pumps early in an accident, if containment cooling heat removal requirements were met, as well as providing that operators had been previously trained to identify and take actions to prevent containment spray pump runout. The team noted that the licensee did not perform a screening or evaluation consistent with industry guidance on 10 CFR 50.59 for crediting operator actions in lieu of automatic actions. Specifically, although the licensee had previously credited operator actions to secure one of two running containment spray pumps, the actions were specific and analyzed to address containment sump suction net positive suction head concerns and to minimize postaccident debris transport inside primary containment, not to address pump runout in order to maintain containment spray system design requirements. The team concluded that a 10 CFR 50.59 applicability screening and evaluation was required to credit these operator actions to specifically protect the containment spray system design against single active failures. Subsequently, the licensee conducted a 10 CFR 50.59 review to credit the manual operator actions to support the single active failure design requirements of the containment spray system.

The team also noted that the licensee's operability evaluation provided that under certain conditions that the running pump would be operated without sufficient net positive suction head for a brief period of time prior to swapping the pump suction to the containment sump resulting in the pump cavitating for a period of approximately five minutes. The licensee determined that cavitation for this short period of time would not result in pump damage. However, the team noted the following additional concerns with the licensee's evaluation: (1) pump cavitation was not part of the design of the containment spray system; (2) the licensee did not address whether cavitation would result in air or gas binding of the pump which could result in inoperability of the pump; (3) the licensee's determination that the pump motor would operate above its service factor at 22 percent during a runout condition but that a licensee referenced evaluation (CR 200702241), which utilized engineering judgment, qualitatively determined that a containment spray pump motor would most likely continue to operate without damage in a runout condition, but also stated there is no formal engineering evaluation data to support this judgment for short term operation beyond the service factor of 15 percent;

and (4) the evaluation utilized containment overpressure during an accident to justify back pressure on the containment spray pumps which reduces pump run-out and motor amperage.

Following the team's on-site inspection, the licensee conducted a phone call with the NRC to communicate the station's plans to assure containment spray system operability prior to plant startup from the forced outage. During the call, the NRC questioned how the licensee had maintained containment cooling design requirements with respect to not only the containment spray system but also the containment coolers. Apparently, the previously approved License Amendment 235, which allowed removing the automatic start feature of the C train containment spray pump also required that in order to do so, that certain aspects of containment cooler operability be maintained. At the end of the inspection, the team could not come to resolution on the impact of past containment cooler operability and single active failure aspects of the containment spray system. Consequently, an URI was opened pending further licensee and NRC review of the licensing and design requirements of the containment cooling design, including the containment spray system and containment coolers, and the applicability and accuracy of License Amendment 235 to this issue. Additionally, further NRC assessment is required to determine the acceptability of relying on operator actions long term to assure that the containment spray design is maintained under pump runout conditions (URI 05000285/2008006-02; "Containment Cooling Design Requirements and Licensing Review").

(Closed) NOV 05000285/2006018-01; Violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions Procedures, and Drawings" for failure to Prescribe Adequate Procedures Maintenance and Testing

On May 29, 2007, the NRC issued an NOV in accordance with 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." The NOV provided that from May 11, 2005, to September 9, 2006, that one train of containment spray system was inoperable due to an improperly installed isolation valve. The valve had been installed improperly due to an inadequate maintenance procedure contrary to the requirement discussed above.

In the Reply to a Notice of Violation, dated June 28, 2007, the licensee provided the details of their evaluation and the corrective actions taken to address the NOV. The licensee provided that the cause of the event was that the maintenance procedure allowed flexibility of performing selected portions of the procedure without providing adequate annotation of risk important steps that could impact the final valve alignment. The licensee also provided that the procedure did not provide detailed acceptance criteria which would assure proper valve installation during the PMT. Key corrective actions completed included revising the procedure, specifying adequate acceptance criteria, and conducting training on maintenance on the valve.

During this inspection, the team reviewed CR 200604627, which documented the licensee's evaluation and corrective actions, and a RCE to determine the completion of corrective actions and to assess the adequacy of the licensee's evaluation. The team noted that a majority of the identified 29 identified actions were complete at the time of the inspection, with the exception of some planned corrective action effectiveness reviews. The team also concluded that the licensee's analyses and conclusions were reasonable. This NOV is closed.

(Closed) NOV 05000285/2007011-02, "Inadequate Emergency Diesel Generator Corrective Measures"

On December 7, 2007, the NRC issued an NOV in accordance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action." The NOV stated that prior to February 14, 2007, the licensee had failed to promptly identify and correct a significant condition adverse to quality involving high resistance across the field flash contacts of a relay in the EDG-1 voltage regulator circuit. The NOV cited two examples: (1) failure to determine the cause of the February 14, 2007, EDG-1 failure, a significant condition adverse to quality, and take corrective action to preclude repetition; and (2) failure to promptly identify and correct a significant condition adverse to quality (high resistance on field flash circuit contacts) after determining that similar OE was applicable.

In the Reply to a Notice of Violation, dated February 15, 2008, the licensee provided the details of their evaluation and the corrective actions taken for both NOV examples. Regarding the OE program, the licensee provided that the reason the violation occurred was that a formalized process for evaluating the potential for applicable OE to represent either a condition adverse to quality or a significant condition adverse to quality was not contained in their procedures. More specifically, once applicability is determined, a process was not in place to prompt further review under the corrective action program process where additional evaluations, such as operability determinations, may need to be performed. Regarding the failure to determine the cause of the field flash failure in a timely manner, the licensee also provided that the reason the violation occurred was that the corrective action process did not contain adequate criteria for determining the significance level of the field flash relay failure. The letter outlined the corrective steps that had been taken to address both violation examples and the corrective steps that would be taken to avoid further violations.

During this inspection, the team reviewed the CRs that were written to address these two violation examples and the resulting root cause analysis. Specifically, the team noted that the licensee had written: (1) CR 200702712 to document the failure to meet the requirements of SO-R-2, the licensee's corrective action program document, in addressing the Relay 2CR contact resistance failure and for inappropriately closing CR 200700725 (DG-1 failed to Field Flash); (2) CR 200703571 to document that the RCE for CR 200700725 and an independent review had identified that the OE program was ineffective in providing a cross-disciplinary review of external OE, and was ineffective in reviewing similar OE that occurs over a large span of time; and (3) CR 200705238 was written to address the NRC findings and the NOV. In conjunction with the latter CR, the licensee performed a root cause analysis. Because of these reviews, the licensee identified the conclusions stated in their reply to the NRC and several contributing causes also outlined in their response to the NOV. In addition, the licensee identified 22 action items addressing root and contributing causes as well as the requirements for effectiveness review. The team concluded that the licensee's analyses and conclusions were reasonable. The team also concluded that the resulting corrective actions were acceptable and that most of the action items had been completed. Additionally, the team determined that the licensee's schedule for completing remaining corrective actions, including future corrective action program enhancements and effectiveness reviews were adequate. This NOV is closed.

03 MANAGEMENT MEETINGS

On April 9, 2008, the team presented the inspection results to Mr. Dave Bannister, Site Vice President and Chief Nuclear Officer, and other members of his staff, who acknowledged the findings. The team asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

D. Bannister, Vice President, Chief Nuclear Officer
G. Cavanaugh, Supervisor, Regulatory Compliance
R. Clemens, Division Manager, Nuclear Engineering
J. Collins, Electrical Maintenance
K. Dworak, Electrical Maintenance
H. Faulhaber, Division Manager, Nuclear Asset Management
M. Frans, Manager, System Engineering
W. Goodell, Division Manager, Quality and Performance Improvement
T. Gurtis, Electrical Maintenance Supervisor
J. Herman, Manager, Engineering Programs
R. Johansen, Manager, Maintenance
D. Kovak, Electrical Maintenance
J. McManis, Manager, Licensing
T. Nellenbach, Plant Manager
R. Short, Manager, Major Projects
M. Smith, Operations Shift Manager
M. Tesar, Division Manager, Nuclear Support
R. Westcott, Manager, Quality

NRC Personnel

J. Hanna, Senior Resident Inspector
J. Kirkland, Resident Inspector
G. Miller, Senior Project Engineer

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000285/2008006-01	URI	High Contact Resistance on Main Steam Bypass Valve Relay Contactors (Section 02.02.d(2))
05000285/2008006-02	URI	Containment Cooling Design Requirements and Licensing Review (Section 02.06)

Opened and Closed

None.

Closed

05000285/2006018-01	NOV	Violation of 10 CFR part 50, Appendix B, Criterion V "Instructions Procedures, and Drawings" for failure to Prescribe Adequate Procedures Maintenance and Testing. (Section 02.06)
05000285/20070011-02	NOV	Inadequate Emergency Diesel Generator Corrective Measures (Section 02.06)

Discussed

05000285/2004003-08	NCV	Failure to Establish an Adequate Test Program for the Backup Nitrogen Supply Systems to the CCW Inlet and Outlet Valves to the Containment Air Cooling Units (Section 02.01.b(3))
05000285/2007011-01	NCV	Inadequate Emergency Diesel Generator Postmaintenance Test (Section 02.01.c(2))
05000285/2007002-03	NCV	Loss of Shut Down Cooling Due to Inadequate Procedure (Section 02.01.c(3))
05000285/2007011-03	NOV	Failure to Provide Procedure for Safety Related Maintenance Activities (Section 02.02.d(2))

LIST OF DOCUMENTS REVIEWED

Condition Reports

200001014	200001071	200001917	200001982	200102050
200102054	200404204	200502389	200505275	200600288
200600458	200600503	200600653	200600750	200600788
200601046	200601424	200601444	200601478	200601714
200601997	200602653	200602855	200603665	200603765
200603808	200604073	200604430	200604627	200605059
200605083	200605150	200605348	200605352	200605629
200700725	200700756	200701020	200701647	200701704
200702580	200702841	200703384	200703814	200703889
200704399	200704144	200704224	200704401	200704402
200704449	200704956	200800308	200800408	200800409
200800410	200800411	200800412	200800431	200800967
200800972	200800978	200801264	200801335	200801419
200801434	200801464	200801465	200801477	200801478
200801498	200801514	200801523	200801539	200801556
200801564	200801572	200801579	200801666	200801679
200801680	200801682	200801683	200801696	200801697
200801698	200801699	200801704	200801711	200801712
200801720	200801734	200801742	200801749	200801763
200801768	200801774	200801776	200801780	200801788

200801801	200801802	200801815	200801819	200801822
200801879	200801884	200801948		

Drawings

B120C11509 - Sheet 1; Schematic Diagram – Field Flashing Control; Revision 10

B120C11509 - Sheet 2; Schematic Diagram – Field Flashing Control; Revision 3

B120F11503 - Sheet 1; Emergency Generators Schematic Diagram, AI-133A & AI-133B; Revision M

B120F14501 - Sheet 1; Schematic Engine Control; Revision 6

B120F14501 - Sheet 2; Schematic Engine Control; Revision 19

EM-204 - Sheet 1; Instrument and Control Equipment List; Revision 10

EM-212 - Sheet 1; Instrument and Control Equipment List; Revision 13

EM-344 - Sheet 1; Instrument and Control Equipment List; Revision 16

EM-345 - Sheet 1; Instrument and Control Equipment List; Revision 4

File 12234; Simplified One Line Diagram, Plant Electrical System P&ID; Revision 128

File 54067; Schematic Diagram for Fuel Oil Transfer Pump FO-37; Revision 3

File 54069; Schematic Diagram for Startup Feedwater Pump FW-54 and Accessories; Revision 2

File 55348; DC Schematic Diesel-Driven Auxiliary Feedwater Pump; Revision 7

44D302335 - Sheet 1; Phase Full Wave SCR Static Exciter; Revision 2

11405E29 - Sheet 6; Containment Sump Isolation Valve Schematic Diagram; Revision 26

11405E51 - Sheet 7; Containment Spray Control Valve HCV-344; Revision 30

11405E51 - Sheet 8; Containment Spray Control Valve HCV-345; Revision 30

11405E137 - Sheet 1; Schematic, Wiring Diagram & Switch Developments for Control Valve YCV-1045 to Steam Driven Aux Feed Water Pump FW-10; Revision 26

11405E143 - Sheet 1; 480V SWGR 1B3C, BKR 1B3C-6 (Unit 503B) Schematic SI-3A; Revision 27

11405E143 - Sheet 2; 480V SWGR 1B4B, BKR 1B4B-1 (Unit 403B) Schematic SI-3B; Revision 3

136B3083 - Sheet 32; Elementary Diagram Ann. Field Contact Scheme; Revision 23

177B2371 - Sheet 386; Motor Control Center 4C1 Unit D01; Revision 12

0223R0454 - Sheet 6; Bus No. 1A1, Power & Control Circuit for Unit 1A1-9 Breaker No. 1A131 – Transf. # T1A-3; Revision No. 12

C-4175; Sheet 5; Control Valve Air Source Valve Lineup / Listing AC System P & ID; Revision 18

C-4175; Sheet 1; Typical Control Valve Air Source Valve Configurations P & ID; Revision 31

EM-1109/1110; Instrument and Control Equipment List; January 11, 2000

Operating Experience Reports

2007011559; Information Notice 2007-09

2007012416; OE25594 Scaffold Construction

2007012665; OE25805 Masoneilan 20000 Series Pressurizer Spray Valve

2007012801; OE 25942 Cable Type Used in Low Voltage Application

2007012840; NRC Bulletin 2007-01

Procedures

EM-RR-DG-1500; Emergency Diesel Generators DG-1 and DG-2 Brush Inspection and Replacement; Revision 3

FCSG-7; Human Performance; Revision 15

GM-PM-MX-0300; Defuel, Clean, Inspect, and Refuel Diesel Fuel Oil Storage Tanks; Revision 11

MD-AD-0013; Detailed Post Maintenance Testing Instructions; Revision 0

MM-PM-PX-0050; Reciprocating Air Compressor SA-1-1 and SA-1-2 Maintenance; Revision 5

MM-ST-DG-0001; Diesel Generator DG-1 Inspection; Revision 61

NOD-QP-21; Operating Experience Program; Revision 22

OI-SC-2; Termination of Shutdown Cooling; Revision 19

OP-ST-AFW-3006; Auxiliary Feedwater System Category A and B Valve Exercise Test; Revision 22

OP-ST-AFW-3009; Auxiliary Feedwater Pump FW-6, Recirculation Valve, and Check Valve Test; Revision 13

PED-SEI-40; AOV Program Plan; Revision 2

PE-PM-FO-1000; Portable Filtering of Fuel Oil Storage Tanks; Revision 3

PE-PM-VX-0405; Diesel Jacket Water Temperature Control Valve Maintenance; Revision 12

PE-PM-VX-0415; Fisher Butterfly Valve Inspection; Revision 3

PE-PM-VX-0416; Masoneilan and Flowseal Butterfly Valve Inspection; Revision 4

PE-RR-SI-0405; Replacement of LCV-383-1 and LCV-383-2 Flange Gaskets; Revision 5

PE-RR-VX-0401S; Inspection and Repair of Fisher 300U/300UR Control Valves; Revision 7

PE-RR-VX-0401S; Inspection and Repair of Fisher 300U/300UR Control Valves; Revision 9

PE-RR-VX-0402S; Maintenance of Masoneilan 32000 Series Butterfly Valves; Revision 7

PE-RR-VX-0410; Inspection and Repair of Fisher "ES" Control Valves; Revision 8

PE-RR-VX-0419N; Inspection and Repair of Non-Safety Related Fisher Controls 9100 Series Butterfly Control Valve Body; Revision 3

PE-RR-VX-0419S; Inspection and Repair of a Safety Related Fisher Controls 9100 Series Butterfly Control Valve Body; Revision 5

PE-RR-VX-0421N; Inspection and Repair of Non-Safety Related Masoneilan Minitork 37000 Series Butterfly Valves; Revision 2

PE-RR-VX-0421S; Inspection and Repair of Safety Related Masoneilan Minitork 37000 Series Butterfly Valves; Revision 7

PE-RR-VX-0434S; Inspection and Repair of a Safety Related Fisher Control 9500 Series Fishtail Disc Butterfly Control Valve Body; Revision 5

PE-RR-VX-0436S; Inspection and Repair of Safety Related Fisher Controls Model 486-U-U Ball Valves; Revision 4

PE-RR-VX-0445; Repair of Anderson Greenwood Type 83 Safety Relief Valve; Revision 3

PE-RR-VX-415S; Inspection and Repair of Safety Related Fisher 7600 Series Valves; Revision 10

QCP-334; Ultrasonic Examination of Liquid Level Measurement; Revision 0

SO-G-07; Operating Manual; Revision 62

SO-M-101; Maintenance Work Control; Revision 74

SO-O-26; Plant Keys; Revision 39

PE-RR-VX-04015; Inspection and Repair of Fisher 3000/300 UR Control Valves; Revision 2

NOD-QP-42; Recovery Plan Oversight Monitoring Program; Revision 0

EM-PM-EX-1101; Preventive Maintenance, Westinghouse Series 2100 - 480 Volt Motor Control Center Maintenance; Revision 19

EM-PM-EX-1100; Preventive Maintenance, 480 Volt Motor Control Center Maintenance; Revision 6

IC-RR-IX-0802; Repair – Rework, Maintenance Instructions for Rosemount Model 1154 Pressure Transmitters; Revision 2

IC-RR-VX-0408; Repair – Rework, Inspection & Repair of Pneumatic Valve Actuators; Revision 5

MD-AD-0013; Administrative Procedure, Detailed Post Maintenance Testing Instructions; Revision 0

MM-RR-MS-0451; Repair – Rework, Inspection & Repair of Main Steam Bypass and Dump Valve Actuators; Revision 2

PE-RR-AE-1000; Repair – Rework, Floodgate Inspection & Repair; Revision 6

PED-SEI-46; Functional Equipment Group (FEG) and Functional Importance Determination (FID) Process; January 25, 2007

SO-R-2; Standing Order, Condition Reporting and Corrective Actionp; Revision 38

EM-PM-EX-0200A; Preventive Maintenance – 4160 Volt Circuit Breaker Inspection; Revision 13

EM-PM-EX-1102; Preventive Maintenance, 480 Volt Motor Control Center Cubicle Maintenance; Revision 3

IC-PM-CCW-0350; Preventative Maintenance Backup Nitrogen Systems; Revision 4

OP-ST-CCW-3005A; Component Cooling Category A and B Valve Exercise Test (for the A and B valves); Revision 7

OP-ST-CCW-3005B; Component Cooling Category A and B Valve Exercise Test (for the C and D valves); Revision 7

NOD-QP-45; Cognitive Trending; Revision 0

NOD-QP-19; Cause Analysis Program; Revision 30

OI-RM-1; RM-064 (Post Accident Main Steam Line); Revision 53

EPIP-EOF-6; Attachment 6.2; Dose Assessment in the Technical Support Center; Revision 36

EPIP-EOF-6; Attachment 6.1; Dose Assessment in the Control Room; Revision 36

EPIP-OSC-1; Attachment 6.2; Emergency Action Levels (EALs); Revision 44

PED-GEI-16; Single Failure Criteria; Revision 3

SO-R-1; Reportability Determinations; Revision 17

OI-ES-1; Operating Instruction Engineered Safeguard Controls - Normal Operation; Revision 23

OI-ES-3; Operating Instruction Engineered Safeguard Controls - Normal Mode 1, 2 and 3 Alignment Check; Revision 9

Work Orders and Work Requests

200552-01	203715-01	233362-01	249599-01	225111-01
298304-01	263000-01	263000-02	263153-01	263153-02
277748-01	298082-01	298363-01	00096945	00243662

Miscellaneous

LIC-07-0062; NRC Inspection Report 05000285/2006018, Reply to a Notice of Violation (NOV) EA-07-047; June 28, 2007

2007 Safety Conscious Work Environment (SCWE) Survey Summary Report; August 22, 2007

Fort Calhoun Station Safety Culture Assessment; January 2007

General Electric Letter - Failure of CR105X Auxiliary Contacts; April 23, 2002

General Electric Instruction Bulletin GEJ-5277A - CR105X Auxiliary Contacts

Fort Calhoun Station Paper; Basis for Time Frame on Testing CR 105 Aux Contacts; March 15, 2008

Fort Calhoun Station Paper; Use of Wet Lubricants Corrective Action Summary; March 14, 2008

SwRI Project 14.12707.01.030; Failure Analysis of GE Circuit Breakers

SwRI Project 18.18056.07.122; Failure Analysis of GE CR 105 X300 Auxiliary Contact Assemblies; July 2007

Critical Equipment (CQE) List, Part Two, Section III; Revision 27

FC-143; Auxiliary Building Log; Revision 93; March 17-19, 2008

2210c; Aux Feedpump FW-6 Recirc Control Valve; Revision 0

PRA Configuration Control; Basis for FCV-1368 Diversion Flow Path

Cross Reference List for RCA Corrective Action Numbers and the Condition Reporting Action Items in Actionway

Maintenance Rule Functions 1710X1 & 1710X2, Main Steam Line Radiation Monitors

PLDBD-EC-32; Instrumentation and Control Systems; Revision 27

Technical Data Book IV.7; Table 2; Effluent Monitor Default Values for Site Area Emergency; Revision 210

Technical Data Book IV.7; Table 1; Process Monitor Setpoints; Revision 210

FC-154B; 50.59 Evaluation; EC 42837; Containment Spray manual actions

Fort Calhoun Station Unit No. 1 License Amendment Request; Reduce the Number of Required Operable Containment Spray Pumps; December 19, 2005

Technical Specifications Bases Change 07-001-00; PAL Door Equalizing Valve; Revision 0

Fort Calhoun Station Unit No. 1 License Amendment Request; Addition of Diesel Generator Fuel Oil, Diesel Generator Lubricating Oil, and Diesel Generator Starting Air Requirements; December 1, 2003

Mitigating Systems Performance Index Basis Document for Fort Calhoun Station; Revision 1

LIST OF ACRONYMS

AFW	Auxiliary Feedwater
AOP	Abnormal Operating Procedure
CFR	Code of Federal Regulations
CR	Condition Report
EAC	Emergency AC Power
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EROP	Equipment Reliability Optimization Project
FID	Functional Importance Determination
GE	General Electric
IMC	Inspection Manual Chapter
IR	Inspection Report
LER	Licensee Event Report
MS	Mitigating System
NCV	Noncited Violation
NOV	Notice of Violation
NRC	Nuclear Regulatory Commission
OE	Operating Experience
PI	Performance Indicator
PMT	Post Maintenance Test
RCE	Root Cause Evaluation
SG	Steam Generator
SSFF	Safety System Functional Failure
URI	Unresolved Item
USAR	Updated Safety Analysis Report

INSPECTION PLAN – FT. CALHOUN STATION 95002

INSPECTION FOR ONE DEGRADED CONRERSTONE OR ANY THREE WHITE INPUTS IN A STRATEGIC PERFORMANCE AREA

Inspection Report Number 05000285/2008006

Background

Safety performance for Fort Calhoun Station for the most recent quarter was within the Degraded Cornerstone Column (Column 3) of the NRC's Action Matrix. Fort Calhoun entered Column 3 in the second quarter of CY 2007 as a result of a White Performance Indicator (PI) for safety system functional failures (SSFF) coincident with a White finding in the mitigating systems cornerstone related to improper valve maintenance activities. Since the White finding was issued at nearly the same time the PI crossed the Green-White threshold, a supplemental inspection per inspection procedure (IP) 95001 was not performed for either issue. Instead, NRC determined a supplemental inspection per IP 95002 would be performed to review the licensee's collective evaluation of both performance issues. Although the SSFF PI returned Green the following quarter, Fort Calhoun Station received a second White finding associated with inadequate emergency diesel generator (EDG) maintenance and corrective actions effective the third quarter of CY 2007. Therefore, Fort Calhoun Station remains in Column 3 based on two White findings in the mitigating systems cornerstone and pending the completion of the IP 95002 supplemental inspection. The PI and inspection findings are described in further detail below.

On April 21, 2007, FCS submitted the first quarter 2007 PI data to the NRC. FCS reported that the Safety System Functional Failure (SSFF) PI in the Mitigating Systems Cornerstone was at the Green-White threshold of five failures. These five failures and their associated Licensee Event Report (LER) numbers are listed below:

1. **LER 2006-002**, "Inadequate Design Control Results in Potentially Insufficient AFW Flow." The power supply to flow transmitter FT-1368 was from non-safety related instrument bus. A design calculation failed to account for MSSV tolerance or back-pressure accumulation, which meant the flow transmitter had a safety function to close the recirc. valve in order to provide sufficient flow. **This condition was reportable per 10CFR 50.73(a)(2)(v)(B), removal of residual heat.**

2. **LER 2006-003**, "TS Violation of Containment Air Coolers Due to Untimely Corrective Actions." Torn dust boots on pneumatic actuators indicating possible actuator leaks were identified on two CCW supply valves to containment air coolers. Also an operability determination (which asserted the valves could perform their function) was incorrect on five other CCW isolation valves. Therefore multiple trains of containment cooling were unavailable simultaneously. **This condition was reportable per 10CFR 50.73(a)(2)(v)(D), mitigate the consequences of an accident.**

3. **LER 2006-005**, "Faulty Maintenance Renders One Train of Containment Spray System Inoperable." The disk to a Vee-Ball valve was installed approximately 90 degrees out of alignment. **This condition was reportable per 10CFR 50.73(a)(2)(v)(D), mitigate the consequences of an accident.**

4. **LER 2006-007**, "Inadequate Seismic Design of RV Head Refueling Stand." Licensee found that, due to an original design oversight, both their new and previously used RV head stands were not seismically designed and if a seismic event did occur during an outage, it could allow the head to fall through the floor damaging both trains of RHR. **This condition was reportable per 10CFR 50.73(a)(2)(v)(B), remove residual heat, (C) control the release of radioactive material, and (D) mitigate the consequences of an accident.**

5. **LER 2006-008**, "Loss of Shutdown Cooling Due to Repressurizing Reactor Coolant System." Reactor Coolant Pumps 'B' and 'C' were secured, which reduced spray flow, an RCS pressure increase and auto closure of SDC isolation valves. **This condition was reportable per 10CFR 50.73(a)(2)(v)(B), removal of residual heat.**

Subsequent to the end of the first quarter, on April 17, 2007, FCS submitted **LER 2007-003** regarding the failure of an EDG with an inoperable containment cooling fan from the opposite bus. In addition, on June 11, 2007, FCS submitted **LER 2007-004** regarding the inadvertent isolation of all containment spray due to an inadequate test procedure. As a result of these two additional reportable failures, the number of safety system functional failures was seven, making this PI White (Regulatory Response Band) for the second quarter of 2007. In the third quarter of 2007, the PI returned Green after FCS retracted LER 2006-007, "Inadequate Seismic Design of RV Head Refueling Stand," and LER 2006-002 became greater than four quarters old.

A White finding related to the containment spray header isolation valve was finalized in a letter dated May 29, 2007. During the Spring 2005 Refueling Outage, FCS performed work on containment spray header isolation Valve HCV-345 to address inconsistent operation identified during previous testing. On three separate occasions HCV-345 had been removed from the system, disassembled, reassembled, and returned to the system. During the Fall 2006 Refueling Outage, the licensee inspected the valve seat rings to determine why reactor coolant system (RCS) water had leaked past the valve and had filled the spray headers inside containment. While performing this maintenance, the system engineer determined that the valve internals for HCV-345 had been installed incorrectly. This improper installation resulted in a condition where the actual position of the valve was nearly opposite of the indicated position. When the valve actuator and remote position indication indicated closed (the normal standby position of the valve) the valve was approximately 66 percent open. When the valve actuator and remote position indication indicated open, the valve was only approximately 20 percent open. In this condition, one train of containment spray was not capable of providing its design flow. The inspectors identified a violation of 10 CFR Part 50, Appendix B, Criterion V, in that inadequate maintenance work instructions contributed to the improper configuration of containment spray header isolation Valve HCV-345 (Ref: NRC IR 05000285/2006018).

The second White finding consisted of two separate violations and was finalized in a letter dated December 7, 2007. The violations were associated with inadequate corrective actions and improper maintenance on the emergency diesel generators. Following a failure of the Train A emergency diesel generator on February 14, 2007, contamination containing dust and oil was found on the field flash relay auxiliary contact surfaces, which apparently caused the failure. NRC inspectors determined there were multiple performance deficiencies in that: (1) maintenance personnel were applying an unapproved wet lubricant to the auxiliary contact sliding mechanisms, contrary to vendor recommendations and in the absence of procedural controls; (2) Fort Calhoun Station staff did not treat the February 14, 2007, emergency diesel generator failure as a significant condition adverse to quality; and (3) actions in response to applicable operating experience were not timely and did not prevent this condition from occurring. The NRC determined that the failure of the Train A emergency diesel generator field flash auxiliary contacts involved two violations of NRC requirements. The first was a violation of 10 CFR 50, Appendix B, Criterion XVI (Corrective Action), with two examples, for the failure to: 1) determine the cause of the February 14, 2007, emergency diesel generator failure, a significant condition adverse to quality, and take corrective action to preclude repetition; and 2) promptly identify and correct a significant condition adverse to quality (high resistance on field flash circuit contacts) after determining that similar operating experience was applicable. The second was a violation of Technical Specification 5.8.1.a (Procedures) for failing to establish a procedure for proper lubrication of the auxiliary contact sliding mechanism, an activity that affected the performance of the emergency diesel generator (Ref: NRC IR 05000285/2007011)

As of the first quarter of CY 2008, the White finding for Valve HCV-345 is being held open pending the successful completion of the supplemental inspection. The EDG White finding remains open until the completion of either the supplemental inspection or four calendar quarters, whichever is greater. If the IP 95002 supplemental inspection is not successfully completed within the first quarter of CY 2008, in the second quarter of CY 2008 FCS will have remained in Column 3 of the Action Matrix for five calendar quarters and will transition to the Multiple/Repetitive Degraded Cornerstone Column (Column 4) per Manual Chapter 0305.

Inspection Objectives

This inspection fulfills the requirements to perform a supplemental inspection subsequent to the identification of two White findings and one White performance indicator at the Ft. Calhoun Station in the Mitigating Systems Cornerstone, resulting in a degraded cornerstone. The inspection objectives are:

- Provide assurance that the root causes and contributing causes are understood for individual and collective (multiple white inputs) risk significant performance issues.
- Independently assess the extent of condition and the extent of cause for individual and collective (multiple white inputs) risk significant performance issues.
- Independently determine if safety culture components caused or significantly contributed to the individual or collective (multiple white inputs) risk significant performance issues.
- Provide assurance that the licensee corrective actions to risk significant performance issues are sufficient to address the root causes and contributing causes, and to prevent recurrence.

Onsite inspection dates

March 10 – 20, 2008

Applicable Inspection Procedures

IP 95002 "Inspection for One Degraded Cornerstone or any Three White Inputs in a Strategic Performance Area," dated October 16, 2006

Prepared by: ______________________ 2/29/08
Z. Dunham, Team Lead Date

Approved by: ______________________ 2/29/08
J. Clark, Chief, Branch E, DRP Date

INSPECTION PLAN DETAILS

I Inspectors

Zachary Dunham (Lead)
Gerond George
Clyde Osterholtz
Chris Long
Neil Della Greca (Contractor)

II Detailed Inspection Schedule

Inspection Preparation at Region IV Office: March 3 - 7, 2008
Onsite Inspection: March 10 - 20, 2008
Entrance Meeting: March 10, 2008, 3 pm
Debrief Meeting: March 20, 2008, 4 pm
Inspection Documentation at Region IV Office: March 24 – 28, 2008
Draft Inspection Report Completed: On or before April 4, 2008
Management Review Completed and Report Issued: On or before April 25, 2008

III Specific Inspection Activities

02.01 Problem Identification

02.01.a Determine that the evaluation identifies who (i.e. licensee, self-revealing, or NRC), and under what conditions the issue was identified.

02.01.b Determine that the evaluation documents how long the issue existed, and prior opportunities for identification.

02.01.c Determine that the evaluation documents the plant specific risk consequences (as applicable) and compliance concerns associated with the issue(s) both individually and collectively.

02.02 Root Cause, Extent of Condition, and Extent of Cause Evaluation

02.02.a Determine that the problem was evaluated using a systematic method(s) to identify root cause(s) and contributing cause(s).

02.02.b Determine that the root cause was conducted to a level of detail commensurate with the significance of the problem.

02.02.c Determine that the root cause evaluation included a consideration of prior occurrences of the problem and knowledge of prior operating experience.

02.02.d. Determine that the root cause evaluation addresses the extent of condition and the extent of cause of the problem.

02.03 Corrective Actions

02.03.a Determine that the appropriate corrective action(s) are specified for each root/contributing cause or that there is an evaluation that no actions are necessary

02.03.b Determine that the corrective actions have been prioritized with the consideration of the risk significance and regulatory compliance.

02.03.c Determine that a schedule has been established for implementing and completing the corrective actions

02.03.d Determine that the quantitative or qualitative measures of success have been developed for determining the effectiveness of the corrective actions to prevent recurrence.

02.04 Independent Assessment of Extent of Condition and Extent of Cause

Perform a focused inspection(s) to independently assess the validity of the licensee's conclusions regarding the extent of condition and extent of cause of the issues. The objective should be to independently sample performance, as necessary, to provide assurance that the licensee's evaluation regarding extent of condition and extent of cause is sufficiently comprehensive.

The following inspection procedures (or portions thereof) may be used to meet this objective (note: this list is not all-inclusive and may change as information is gathered during preparation and inspection):

02.04.a IP 62700: Maintenance Program Implementation

02.04.b IP 71111.12: Maintenance Effectiveness

02.04 c IP 71111.19: Post Maintenance Testing

02.04 d IP 71111.22: Surveillance Testing

02.04 e IP 71841: Human Performance

02.04 f IP 73756: In-Service Testing of Pumps and Valves

02.04 g IP 93805: Maintenance Program

02.05 Safety Culture Consideration

Perform a focused inspection to independently determine that the root cause evaluation appropriately considered whether any safety culture component caused or significantly contributed to any risk significant performance issue. If a weakness in any safety culture component did cause or significantly contributed to such an issue and the licensee's evaluation did not recognize that cause or contribution, refer to IMC 0305.

02.06 Evaluation Against IMC 0305 Criteria for Treatment of Old Design Issues

The licensee has not requested credit for a self-identification of an old design issue. Therefore, this inspection will not evaluate any issues against IMC 0305 criteria for treatment of old design issues.

IV <u>HRMS and Time Charge Information</u>

This is a supplemental inspection with an allotted time of 40 to 240 hours of direct inspection. All time spent shall be charged to Inspection report 05000285/2008006 and to the following IPE codes, as appropriate:

Travel:	**AT**
Preparation:	**SEP**
Inspection:	**SP with IP 95002**
Documentation:	**SED**

V <u>Documentation of Findings</u>

The report will be prepared in accordance with the guidance in IMC 0612 and regional guidance. Should new or additional examples of performance issues be identified by this inspection, the new issues will be categorized using the Significance Determination Process and the corresponding supplemental inspection procedure will be performed if needed.

VI <u>Interface and Coordination Meetings</u>

<u>Team Meetings</u>

Team meetings will be held daily starting on Tuesday, March 11. The intent is to allow each inspector, including the team leader, to discuss the day's activities. Additionally, the team leader will meet periodically with the team members during the inspection preparation week in Region IV to discuss any preliminary issues and to address any preparation needs.

<u>Daily Debrief with Regional Management</u>

The team leader will conduct a daily phone call with regional management to update the region on inspection status and summary of developing issues.

<u>Meetings with the licensee</u>

An entrance meeting will be held on March 10, at 3:30 pm.

Daily debriefs with the licensee will start Tuesday, March 11 at 8:30 am. These daily meetings normally will be between the team lead and the licensee; individual team members may be needed on occasion to elaborate on a complicated issue.

The inspection team will conduct a debrief meeting on March 20, 2008, at 4:00 pm.

VII Work Hours

March 11 – 14 and March 17 – 20; 7:15 am – 5:00 pm
March 15; 8:00 am – 1:00 pm

VII Specific Inspection Assignments

Zach Dunham – Manage and assist the team as follows:

- Assist team members with their assigned responsibilities as needed.
- Assist with assessment and characterization of any identified performance issues, findings, or observations.
- Ensure completion of inspection plan.
- Conduct periodic briefings with regional management.
- Conduct periodic briefings with licensee.
- Formulate overall conclusions regarding independent NRC inspections of licensee performance and self-assessments, extent of cause, and extent of condition evaluations.

Chris Long – Review, inspect, and independently assess the following:

- Activities described in section 02.01 for the Safety System Functional Failures white performance indicator.
- Activities described in section 02.02 for the Safety System Functional Failures white performance indicator.
- Activities described in section 02.03 for the Safety System Functional Failures white performance indicator.
- Activities described in section 02.04 for the Safety System Functional Failures white performance indicator.
- Assist in the completion of section 02.05 for the Safety System Functional Failures white performance indicator.
- Assess adequacy of licensee's extent of cause and extent of condition, if applicable, to other safety significant systems.
- Inspection and closeout LER's 05000285/2006-005-00, "Faulty Maintenance Renders One Train of Containment Spray System Inoperable," and 05000285/2007-03-00, "Inoperability of a Diesel Generator with Inoperable Containment Spray Pump from the Opposite Bus," if time allows and warranted.
- Conduct a sampling of other potentially reportable safety system failures since 2006 and assess adequacy of licensee's evaluation of the failure and applicability of reporting under the SSFF PI.
- Assess adequacy of licensee's assessment and implementation of corrective actions to address NRC PI MSPI – Emergency AC Power Systems (Green, but has been reported near the Green/White threshold for past four quarters).

Gerond George – Review, inspect, and independently assess the following:

- Activities described in section 02.01 for the white finding associated with inadequate maintenance of HCV-345.
- Activities described in section 02.02 for the white finding associated with inadequate maintenance of HCV-345.

- Activities described in section 02.03 for the white finding associated with inadequate maintenance of HCV-345.
- Activities described in section 02.04 for the white finding associated with inadequate maintenance of HCV-345.
- Assist in the completion of section 02.05 for the white finding associated with inadequate maintenance of HCV-345.
- Inspection and closeout VIO 05000285/2006018-01, "Violation of 10 CFR 50, Appendix B Criterion's for Failure to Prescribe Adequate Procedures for Maintenance and Testing," if warranted.
- Assess adequacy of licensee's maintenance practices for valves similar to HCV-345. Observe maintenance activities if available.
- Assess adequacy of licensee's extent of cause and extent of condition, if applicable, to other safety significant systems.
- Inspect adequacy of licensee maintenance practices and post-maintenance testing for diesel generator mechanical components.

Neil Della Greca – Review, inspect, and independently assess the following:

- Activities described in section 02.01 for the white finding associated with inadequate maintenance of diesel generator field flash relay contacts.
- Activities described in section 02.02 for the white finding associated with inadequate maintenance of diesel generator field flash relay contacts.
- Activities described in section 02.03 for the white finding associated with inadequate maintenance of diesel generator field flash relay contacts.
- Activities described in section 02.04 for the white finding associated with inadequate maintenance of diesel generator field flash relay contacts.
- Assist in the completion of section 02.05 for the white finding associated with inadequate maintenance of diesel generator field flash relay contacts.
- Inspection and closeout of VIO 05000285/2007011-02, "Inadequate Emergency Diesel Generator Corrective Measures," if warranted.
- Inspection and closeout of VIO 05000285/2007011-03, "Failure to Provide Procedure for Safety Related Maintenance Activities," if warranted.
- Assess adequacy of licensee's maintenance practices for installation and maintenance of electrical relays and contacts. Observe maintenance activities if available.
- Assess adequacy of licensee's extent of cause and extent of condition, if applicable, to other safety significant systems.
- Inspect adequacy of licensee maintenance practices and post-maintenance testing for diesel generator electrical components.

Clyde Osterholtz – Review, inspect, and independently assess the following:

- Activities described in section 02.05 for the Safety System Functional Failures white performance indicator.
- Activities described in section 02.05 for the white finding associated with inadequate maintenance of HCV-345.
- Activities described in section 02.05 for the white finding associated with inadequate maintenance of diesel generator field flash relay contacts.

- Assist other team members in the conduct of their inspections, if needed, as time allows.