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

August 7, 2012

Mr. Eric W. Olson
Site Vice President, Operations
Entergy Operations, Inc.
River Bend Station
5485 U.S. Highway 61N
St. Francisville, LA 70775

SUBJECT: RIVER BEND STATION - NRC AUGMENTED INSPECTION TEAM REPORT 05000458/2012009

Dear Mr. Olson:

On July 11, 2012, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your River Bend Station. The enclosed inspection report documents the inspection results, which were discussed with you and other members of your staff during a public exit meeting conducted on July 11, 2012.

During a reactor startup on May 24, 2012, operators at River Bend Station initiated a manual scram of the reactor from 33 percent reactor power. The reactor scram was the result of a loss of feedwater, circulating water, and nonsafety-related cooling water caused by an electrical fault associated with a main feedwater pump motor. The fault was not isolated by the motor feeder breaker due to a failed relay, resulting in the trip of the supply breaker for the 13.8 kV nonsafety-related electrical bus. Because of a previous cable failure and fire on May 21, 2012, all operating circulating water pumps and nonsafety-related service water pumps were powered through this supply breaker. The loss of the running pumps resulted in the loss of condenser vacuum and cooling water to turbine building and safety-related loads. Both divisions of safety-related standby service water started and restored cooling to the safety-related loads.

All three safety-related electrical buses remained energized from offsite power, and all three diesel generators remained operable. No emergency action level declaration was made, and there were no radiological releases due to this event.

In accordance with Management Directive 8.3, “NRC Incident Investigation Program,” deterministic and conditional risk criteria were used to evaluate the level of NRC response for this operational event. Because two deterministic criteria were met (multiple failures in systems used to mitigate the event and questions pertaining to licensee operational performance), and the conditional core damage probability for the event was originally estimated to be in the range for an augmented inspection, Region IV concluded that the NRC response should be an augmented inspection team.

Based on inspection, the team concluded that: (1) the reactor plant responded to the event as designed and safety system functions were maintained; and (2) equipment issues, some of which you had knowledge of but had not yet corrected, contributed to the significance of the event. The purpose of this inspection was to gather facts and identify issues requiring follow-up, and, as such, no findings were identified. Items requiring additional follow-up are documented as unresolved items in the enclosed report. NRC inspectors verified that equipment issues required to be resolved before plant startup were adequately resolved.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's Agencywide Document Access and Management 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,

/RA/

Elmo E. Collins
Regional Administrator

Docket No.: 05000458
License No: NPF-47

Enclosure:
1. Inspection Report 05000458/2012009

w/Attachments:
1. Supplemental Information
2. Sequence of Events
3. Augmented Inspection Team Charter

cc: w/Enclosure(s)

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EXECUTIVE SUMMARY

On May 26, 2012, an Augmented Inspection Team was dispatched to River Bend Station to gather facts and understand the circumstances surrounding the loss of normal service water and reactor scram event that occurred during a reactor startup on May 24, 2012. The reactor scram was the result of a loss of feedwater, circulating water, and nonsafety-related cooling water caused by an electrical fault associated with a main feedwater pump motor. The fault was not isolated by the motor feeder breaker due to a failed lockout relay, which caused the supply breaker for the 13.8 kV nonsafety-related electrical bus to trip and clear the fault. Because of a previous cable failure and fire on May 21, 2012, all operating circulating water pumps and normal service water pumps were powered through this supply breaker. The loss of the running pumps resulted in the loss of condenser vacuum and cooling water to turbine building and safety-related loads. Both divisions of safety-related standby service water started and restored cooling to the safety-related loads, and all safety systems performed their functions to support a safe shutdown and cooldown of the plant.

The augmented inspection team concluded the significance of the main feedwater pump motor fault was increased by equipment issues and plant conditions that existed prior to the event. The augmented inspection team identified eight unresolved items requiring follow-up inspection to determine the existence and significance of any associated performance deficiencies:

1) Main control room annunciator control and conduct of operations.

2) Past operability of the reactor core isolation cooling system.

3) Implementation of the procedure for Infrequently Performed Tests or Evolutions.

4) Corrective action program implementation for a prior lockout relay failure in February 2011.

5) Implementation of vendor and industry recommended relay testing and maintenance.

6) Implementation of the station Cable Reliability Program.

7) Onsite Safety Review Committee implementation.

8) Ability to promptly staff the fire brigade at all times during plant operation.

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	05000458
License:	NPF-47
Report:	05000458/2012009
Licensee:	Entergy Operations, Inc.
Facility:	River Bend Station
Location:	5485 U.S. Highway 61 St. Francisville, LA 70775
Dates:	May 26 through July 11, 2012
Inspectors:	G. Miller, Chief, Engineering Branch 2 S. Alferink, Reactor Inspector, Engineering Branch 2 S. Garchow, Senior Operations Inspector, Operations Branch S. Graves, Senior Reactor Inspector, Engineering Branch 2
Approved By:	Vincent G. Gaddy, Chief, Project Branch C Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000458/2012009; 05/26/2012 – 07/11/2012; River Bend Station; Augmented Inspection Team

An Augmented Inspection Team was dispatched to the site on May 26, 2012, to assess the facts and circumstances surrounding the loss of normal service water and reactor scram event that occurred on May 24, 2012. The team was established in accordance with NRC Management Directive 8.3, "NRC Incident Investigation Program," and implemented using Inspection Procedure 93800, "Augmented Inspection Team." The inspection was conducted by a team of inspectors from the NRC's Region IV office. The team identified eight issues that will require additional NRC inspection. These issues are tracked as unresolved items in this report.

- On May 26, 2012, an Augmented Inspection Team was dispatched to River Bend Station to gather the facts and information necessary to understand the circumstances surrounding the loss of normal service water and reactor scram event that occurred during a reactor startup on May 24, 2012. The reactor scram was the result of a loss of feedwater, circulating water, and nonsafety-related cooling water caused by an electrical fault associated with a main feedwater pump motor. The fault was not isolated by the motor feeder breaker due to a failed lockout relay, which caused the supply breaker for the 13.8 kV nonsafety-related electrical bus to trip, clearing the fault. Because of a previous cable failure and fire on May 21, 2012, all operating circulating water pumps and normal service water pumps were powered from this supply breaker. The loss of power to the running pumps resulted in the loss of condenser vacuum and cooling water to turbine building and safety-related loads. Both divisions of safety-related standby service water started and restored cooling to the safety-related loads, and all safety systems performed their functions to support a safe shutdown and cooldown of the plant.

  The team concluded that the operator actions taken in response to the event were appropriate and that safety system functions were maintained; however, the team also concluded the significance of the main feedwater pump motor fault was increased by equipment issues and plant conditions that existed prior to the event. The augmented inspection team identified eight unresolved items requiring follow-up inspection to determine the existence and significance of any associated performance deficiencies.

A. <u>NRC-Identified Findings and Self-Revealing Findings</u>

No findings were identified.

B. <u>Licensee-Identified Violations</u>

None.

REPORT DETAILS

1.0 Event Chronology (Charter Item #1)

The team developed and evaluated a timeline of significant events from the reactor scram and cable fire on May 21 until the plant reached cold shutdown conditions following the May 24 loss of normal service water and reactor scram event. The team developed the timeline, in part, through a review of control room alarm logs; control room operator log entries; parameter plots from the plant computer; review of post-event statements from the on-shift operators; and interviews with plant fire brigade personnel, system engineers, and electrical maintenance personnel.

1.1 Summary of the Sequence of Events

On May 21, 2012, River Bend Station was operating at 100 percent power with no plant evolutions in progress, no transmission switching events occurring, and no severe weather conditions. All plant systems were aligned and performing as designed. At 2:52 p.m., the site experienced an automatic reactor scram due to a turbine trip caused by low condenser vacuum. The low condenser vacuum condition resulted from the trip of the nonsafety-related 4160 V bus (NNS-SWG2A) that powered two of the four circulating water pumps. Five minutes later, the control room received a report of a fire in electrical underground cable vault EMH1A. The fire brigade was dispatched to investigate the report. Upon arrival, the fire brigade discovered a small fire in the uppermost cable tray. The fire brigade used portable extinguishers to put out the fire. At 3:15 p.m., the fire brigade reported that the fire in the underground cable vault was out.

Subsequent inspections determined that an electrical fault had occurred in one of the 13.8 kV feeder cables supplying the 4160 V bus. The supply breaker (NPS-SWG1A ACB07) tripped in response to the fault, isolating the bus and resulting in the trip of two of the four circulating water pumps and the subsequent reactor scram due to low condenser vacuum.

On May 22, the licensee closed a tie breaker to power nonsafety-related 4160 V bus NNS-SWG2A from the opposite train switchgear. This resulted in all circulating water pumps and normal service water pumps receiving power through nonsafety-related 4160 V bus NNS-SWG2B. On May 23, the licensee commenced reactor startup.

On May 24, the reactor plant was operating at 33 percent power with one feedwater pump (FWS-P1C) and two circulating water pumps (CWS-P1B and CWS-P1D) in service. Shortly before 1:48 p.m., operators started the feedwater pump B (FWS-P1B). Shortly after the feedwater pump was started, a fault occurred in the feedwater pump motor termination box. The fault was not isolated by the motor feeder breaker due to a failed 86 lockout relay. As a result, the supply breaker for the nonsafety-related 13.8 kV supply bus NPS-SWG1B tripped to clear the fault. This resulted in the loss of power to all running feedwater, circulating water, and normal service water pumps.

At 1:48 p.m. on May 24, the operators initiated a manual reactor scram due to the trip of all running feedwater and circulating water pumps, and immediately began implementing procedures EOP-1, “Reactor Pressure Vessel Control,” and EOP-3, “Secondary Containment and Radioactive Release Control.” The operators initiated the reactor core isolation cooling system per procedure EOP-1 for reactor level control.

Soon after the manual scram, the control room received a report of smoke from the circuitry board for feedwater pump B. The fire brigade was dispatched. At 1:58 p.m., the fire brigade reported that the smoke was dissipating and there was physical damage to the connection box, but no visible fire was identified.

At 3:01 p.m., the licensee began restoring power to the train B nonsafety-related busses by connecting them to the associated train A busses. With the exception of the bus providing power to the circulating water and normal service water pumps, the train A busses were available and could provide power to the train B busses. The train A bus providing power to the circulating water and normal service water pumps remained unavailable due to the May 21 cable failure.

During the cooldown, the operators used the reactor core isolation cooling system for level control and the safety relief valves for pressure control. At 3:34 p.m., reactor coolant level reached a Level 8 condition, and the reactor core isolation cooling system automatically stopped running. The safety relief valves were subsequently closed, and the reactor core isolation cooling system was restarted after reactor vessel water level was reduced below Level 8. The licensee continued to cooldown the plant using the reactor core isolation cooling system and the safety relief valves until the residual heat removal system could be placed in service. The licensee reached cold shutdown conditions at 2:00 am on May 25.

There were no radiological releases due to this event.

A detailed sequence of events is provided in Attachment 2 to this report.

2.0 Evaluation of Licensee Actions (Charter Item #2)

a. Inspection Scope

The team conducted an independent review of licensee actions to determine if licensee staff responded properly during the event. The inspectors specifically assessed the following areas:

- Immediate actions by the control room staff to stabilize the plant in hot standby using abnormal and emergency operating procedures.
- Control room staff actions to cool the plant down to cold shutdown.
- Other relevant operator actions, including operation of the reactor core isolation cooling system.
- Event classification and reporting.

To assess the overall performance of the operating crew, the inspectors interviewed on-shift personnel and reviewed the post-trip report, which included control room logs, operator statements, and plant data trends. With respect to operator awareness and decision-making, the team focused on the effectiveness of control board monitoring, training for emergency operating procedure implementation, technical decision-making, and the work practices of the operating crew. With respect to command and control, the team focused on actions taken by the control room supervision in managing the operating crew's response to the event. The team also discussed these aspects with the resident inspector, who had observed the crew in the control room during the actual plant transient.

To gain additional perspective of operator performance, the team also observed simulator scenarios and a reactor startup in the main control room. Control room observation was essentially continuous over a two-day period.

b. Observations

The team concluded the operator actions taken in response to the May 24 event were appropriate and that safety system functions were maintained; however, the team identified two unresolved items for additional inspection involving operator performance and the design and operation of the reactor core isolation cooling system.

1) Main Control Room Annunciator Control and Conduct of Operations

Introduction. The team identified an unresolved item associated with the operating crew's use of human performance tools to reduce the probability of making errors during an event.

Description. This unresolved item was the result of observations made in the main control room and while observing operating crew performance on the simulator. The observations included an operator response to a plant transient requiring the use of the licensee's abnormal and emergency operating procedures. The team identified the following:

- In the main control room and during the simulator scenario, the use of three-way communications was inconsistent. Three-way communication is an error-prevention tool in which the receiver of a communication repeats the message back to the sender, and the sender then confirms or corrects the repeat back. The team observed instances in which messages were not repeated back to the sender, the sender did not acknowledge the repeat-back, or the repeat-back was incorrect and not corrected by the sender.

- During the simulator exercise, the team observed operators silencing annunciators without visually scanning the panels to identify what parameter had just alarmed. The inspectors also observed that during startup preparations in the main control room, operators were unable to determine the precise time an annunciator had been received for the residual heat removal system. The simulator observations were similar to observations made by the resident inspectors in the control room during the actual event. This practice can lead to important alarms or plant conditions not being recognized and subsequent remedial actions not being taken.

- During the simulator observations, the team noted that operators silenced many alarms and left them in a fast-flash state (not acknowledged) for extended periods of time. The number of fast-flashing alarms increased over the course of the scenario, making it more difficult for operators to identify new alarms as they annunciated. This is similar to observations made in the main control room during the actual plant transient.

- During the simulator exercise, members of the crew provided no “Updates.” Updates are usually conducted when there is a change in a key parameter, to ensure the entire crew is aware of the change. Knowledge of a change in a key parameter can change the flowpath through an abnormal or emergency operating procedure or change crew priorities in mitigating the event.

The operator behaviors observed by the team did not result in any actual consequences during the event response, but they are an area the team identified for further inspection: Unresolved Item URI 05000458/2012009-01, “Main Control Room Annunciator Control and Conduct of Operations.”

2) <u>Past Operability of the Reactor Core Isolation Cooling System</u>

<u>Introduction</u>. The team identified an unresolved item associated with a spurious isolation of the steam supply to the reactor core isolation cooling system during the reactor scram event on May 21, 2012. The licensee had implemented a design modification in 2007 intended to prevent spurious isolations of the reactor core cooling system steam supply.

<u>Description</u>. The reactor core isolation cooling system consists of a steam-driven pump which supplies cooling water to the reactor vessel when the reactor vessel is isolated and the normal feedwater supply is not available. The operability of the reactor core isolation cooling system provides adequate core cooling such that actuation of any of the emergency core cooling subsystems is not required in the event of isolation of the reactor vessel accompanied by the loss of feedwater flow.

On May 21, 2012, the steam supply to the reactor core isolation cooling system pump isolated following the main turbine trip on low condenser vacuum. The cause of the isolation was a false high steam flow isolation signal from differential pressure transmitter E31-PDTN084B. Control room operators subsequently reset the isolation signal and restored the reactor core isolation cooling system. The licensee documented the spurious isolation in Condition Report CR-RBS-2012-03439 and concluded the reactor core isolation cooling system was degraded but remained operable.

Previous operating experience at River Bend Station and other boiling water reactors demonstrated that a sudden change in steam pressure (such as that caused by a main turbine trip) can cause differential pressure instruments in the system to register a false high steam flow reading and isolate the steam supply to the reactor core isolation cooling pump, making the pump unavailable. Condition Report CR-RBS-2004-02906 documented an isolation of the reactor core isolation cooling system steam supply following a main turbine trip and scram at River Bend Station in 2004.

The licensee implemented a modification in 2007 to supply water from the control rod drive system to condensing pots used by the differential pressure instruments to maintain the sensing lines for the instruments filled with water, thus reducing the sensitivity of the instruments to sudden pressure spikes. The modification was successful in reducing the magnitude and duration of the false high steam flow signal from transmitter E31-PDTN084B following the turbine trip on May 21, but the signal was still large enough to cause a spurious isolation of the reactor core isolation cooling system steam supply.

Following the May 24 loss of normal service water and scram event, the licensee developed modification EC-37843 to add a time delay to the high steam flow transmitters to prevent future spurious steam supply isolations. The licensee implemented this modification on May 31 prior to restart of the plant following the May 24 scram.

The team concluded the corrective action to add a time delay the isolation signal was appropriate and consistent with industry operating experience; however, the team concluded that additional inspection was needed to assess the operability of the reactor core isolation system prior to the implementation of the time delay modification: Unresolved Item URI 05000458/2012009-002, “Past Operability of the Reactor Core Isolation Cooling System.”

3.0 Assess Procedure Use and Adequacy (Charter Item #3)

a. Inspection Scope

The team reviewed the plant abnormal and emergency operating procedures used by the operators to respond to the event. The review focused on the adequacy of procedural guidance, operating crew use of procedures, and whether operator training supported the use and knowledge base of the emergency operating procedures. The team also conducted operator interviews and reviewed written operator comments, operator log entries made during the event, and the post scram recovery documentation.

The team also observed simulator scenarios and a reactor startup in the main control room on June 1-2, 2012. The control room observation included operating crew performance during a reactor startup, response to two leaking safety relief valves, implementation of the Infrequently Performed Tests or Evolutions procedure, and the subsequent reactor shutdown.

b. Observations

The team determined that, overall, licensee procedures were adequate to respond to the event. However, the team identified one unresolved item requiring follow-up inspection involving implementing the Infrequently Performed Tests or Evolutions procedure for two leaking safety relief valves.

Introduction. The team identified an unresolved item associated with the licensee's implementation of the guidance specified in procedure EN-OP-116, "Infrequently Performed Tests or Evolutions," Revision 9.

Description. During the reactor startup which commenced on June 1, 2012, following the May 24 event, the operating crew received a safety relief valve acoustical monitor alarm when reactor pressure reached approximately 600 pounds per square inch (psig). The crew determined that two safety relief valves were leaking, and decided to hold reactor pressure at the current value in order to minimize the leak rate into the suppression pool. The licensee decided to cycle the safety relief valves open then closed in an attempt to reseat the valves. Based on vendor input, the licensee determined the valves should be cycled at 900 psig reactor pressure. The operators successfully cycled one safety relief valve, but the valve continued to leak. The licensee subsequently shut down on June 2 and cooled down the plant to implement repairs to the leaking valves.

Since the cycling of relief valves is an activity not typically performed during startup, the operators appropriately decided the evolution would be performed using the guidance contained in procedure EN-OP-116, "Infrequently Performed Tests or Evolutions," Revision 9. This procedure provides additional pre-planning steps and controls for use as an error prevention tool when conducting non-routine evolutions. The inspectors noted the following during the performance of the evolution:

- The approved pre-job brief checklist required the establishment of a list of potential problems and associated contingencies. A handwritten note indicated the only potential problem was an "SRV sticks open." There was no associated contingency listed. The control room crew discussed this evolution and identified additional concerns such as: reactor pressure control with only one bypass valve approximately 20 percent open; reactor level control at low power; reactor power response with power on range 8-10 of the Intermediate Range Monitors; safety relief valve leak rate increasing with increasing reactor pressure; and the length of time the valve should be left open before being shut. The inspectors concluded the pre-plan developed from the "Infrequently Performed Tests or Evolutions" procedure did not comprehensively address potential problems associated with the cycling of safety relief valves.

- The controlling document for performing the cycling of the safety relief valves was procedure AOP-0035, "Safety Relief Valve Stuck Open." However, because this procedure was written assuming the reactor was in Mode 1, the bulk of the guidance was not applicable to the situation faced by the crew. Consequently, over the course of the morning, several discussions were held among the operators on how to set up the initial conditions for the evolution as well as defining the abort and contingency criteria. The discussions concerning initial conditions and abort criteria continued up to the point when the safety relief valve was opened.

The Infrequently Performed Tests or Evolutions procedure required plant system or component initial conditions to be identified. The operating crew concerns discussed above were not addressed by the controlling pre-plan developed from the Infrequently Performed Tests or Evolutions procedure and, consequently, the crew established and implemented the initial conditions. For example, the pre-plan document did not address reactor power or initial bypass valve position, so the operators withdrew control rods to increase reactor power and isolated various steam drain valves and other house loads. These actions were performed to open the turbine bypass valves further for adequate pressure control when cycling the safety relief valves. The inspectors determined the conditions established and the actions taken by the operators were appropriate.

The inspectors determined the operating crew was effective in looking ahead and considering the different variables that could lead to an undesired transient; however, these actions the crews took in response to existing conditions rather than through a specific controlling pre-plan, developed using the Infrequently Performed Tests or Evolutions procedure. The inspectors concluded that although the procedure was appropriately referenced, it did not appear to have been effectively implemented for its intended purpose. The team concluded additional inspection is required to assess the effectiveness of the licensee's use of the Infrequently Performed Tests or Evolutions Procedure: Unresolved Item URI 05000458/2012009-03, "Implementation of the Procedure for Infrequently Performed Tests or Evolutions."

4.0 Plant Response (Charter Item #4)

a. Inspection Scope

The team assessed whether plant systems had responded as expected by comparing the actual plant response to plant design and the applicable safety analyses.

The team compared plant parameter trend graphs generated using data from the plant computer to expected trends based on analysis. The team also reviewed the control room log entries made during the event, observed the event on the simulator for the same initial conditions and event initiators, and interviewed the licensed operators who were on-shift during the event.

b. Observations

The team determined the plant had responded as designed, that all assumptions in the accident analysis appropriately bounded the event, and that no unanalyzed condition was identified for this event. The team verified that all equipment assumed to operate in the loss of all high pressure feedwater accident analysis operated to mitigate the event.

5.0 Main Feedwater Pump Motor Fault (Charter Item #5)

a. Inspection Scope

The team reviewed the licensee’s efforts to determine the cause of the electrical fault in nonsafety-related motor-driven main feedwater pump FWS-P1B. The team reviewed the licensee’s preliminary cause evaluations and corrective action documents; vendor documents including the vendor test report from the previous overhaul and the current overhaul test report and conclusions; and historical electrical test results including polarization index tests, high voltage surge tests, and step-voltage tests for all main feedwater pump motors. The team reviewed the results of the Baker Advanced Winding Analyzer testing and discussed the results with the licensee’s motor engineer. The team also reviewed the licensee’s diagnostic testing reports for all the main feedwater pump motors and cable testing results.

The team interviewed engineering staff involved in initial troubleshooting of the motor failure and discussed the licensee’s plans and schedules to establish the extent of condition and failure mode. The team also held discussions with the vendor contracted to prepare the replacement motor for connection to the electrical distribution system, walked down the refurbished replacement motor, and held discussions with maintenance personnel involved with the replacement.

b. Observations

When the licensee attempted to start non-safety related motor-driven main feedwater pump FWS-P1B, an electrical fault occurred which resulted in an overcurrent condition in feedwater pump 13.8 kV circuit breaker NPS-SWG1B ACB28. Breaker ACB28 failed to trip and clear the fault, which resulted in tripping of the upstream feeder circuit breaker and loss of 13.8 kV bus NPS-SWG1B.

After the motor was removed from service, the licensee performed a preliminary investigation using a Baker Advanced Winding Analyzer testing system. The testing provided inconclusive results, prompting the licensee to ship the motor to an electric motor vendor with additional capabilities for more in-depth forensic analysis.

After preliminary testing, the licensee identified that the A-phase motor line termination lug had been inadequately crimped when the motor was last refurbished. The licensee concluded that this loose connection may have caused an internal electrical fault in the motor. Troubleshooting also identified that the motor neutral connection lead to the C-phase current transformer had failed due to excessive heat and had become detached, as evidenced by burn markings on the wiring and inside the motor connection box.

As part of the extent-of-condition review, the licensee developed a listing of medium-voltage motors that had been repaired or refurbished since 2008 as candidates for additional inspection. The licensee also contacted the vendor who had performed the motor-lead terminations on the failed motor, to determine which other motors the vendor had worked. The team reviewed the motors identified by the licensee for further evaluation and lug inspections and noted that two remaining feedwater pumps, FWS-P1A and FWS-P1C, had not been included as part of the extent-of-condition testing since they were installed, prior to 2008. The licensee subsequently added the remaining feedwater pump motors to the list.

The licensee developed a plan to inspect the motor connections using a combination of thermography and visual examinations. Longer-term corrective actions would also include the installation of observation ports in the motor connection box covers to facilitate thermography of current transformer connections. The team determined that thermography testing should provide indications of high resistance connections, but also noted the existing thermography program had failed to identify the loose motor lug during routine testing. The licensee decided to perform the extent-of-condition thermography inspections with the motor connection box covers removed to provide a clearer view for the thermographic camera. This testing was in progress when the team left the site.

The licensee also determined that they had previously allowed the local vendor to use equipment that was not included in the licensee's measurement and test equipment control program. The licensee entered this issue in their corrective action program as Condition Report CR-RBS-2012-03667. The licensee reviewed the local vendor's equipment against their procedures before re-termination of the replacement feedwater pump motor connections.

The team determined that the corrective actions taken for the extent-of-condition review related to the failure of feedwater pump motor FWS-P1B appeared appropriate. The team reviewed the licensee's preliminary conclusions and determined that the licensee efforts to identify the fault in the main feedwater pump motor also appeared appropriate. On June 21, 2012, the licensee generated Condition Report CR-RBS-2012-04199 which documented the receipt of the electrical motor vendor failure report for the feedwater pump motor. The vendor concluded that the most likely cause of the motor failure was the failure of the crimp on the motor winding lug. The vendor also identified that the motor had been subjected to partial electrical discharges in the windings, which would eventually result in the failure of the winding insulation. The team determined that the licensee's preliminary conclusions and the vendor conclusions were consistent and were appropriate. The vendor was performing additional motor testing, and these test results will be reviewed when available.

6.0 Lockout Relay Failure (Charter Item #6)

a. Inspection Scope

The team reviewed the licensee's efforts to identify the cause of the 86 lockout relay failure on the 13.8 kV main feedwater pump circuit breaker NPS-SWG1B ACB28. The team evaluated the extent of condition for the failure mode, including whether this failure was related to a similar failure of the 86 lockout relay for circulating water cooling tower C on February 12, 2011. The team also assessed the licensee's overall plan and schedule for lockout relay inspections to determine whether the corrective actions identified were appropriate and timely, and whether the licensee had adequately considered safety significance.

The team held discussions with component engineers, system engineers, and maintenance personnel regarding relay maintenance and the testing procedure developed for the lockout relay extent of condition review. The team observed the testing process for General Electric HEA61 relays and reviewed work orders used for the testing.

b. Observations

The team identified two unresolved items requiring follow-up inspection associated with the 86 lockout relays.

1) Corrective Action Program Implementation for Prior Lockout Relay Failure in February 2011

Introduction. The team identified an unresolved item associated with the implementation of corrective actions developed as a result of the failure of a General Electric Type HEA61 lockout relay in 13.8 kV circuit breaker NPS-SWG1A ACB05 in February 2011. This failure resulted in a fire in bus ducting connecting 480 V transformer NJS-X2C to Cooling Tower 1C Load Center NJS-SWG2C.

Description. On February 12, 2011, an electrical fault resulted in an overcurrent condition through 13.8 kV circuit breaker NPS-SWG1A ACB05 and a subsequent bus duct fire. The licensee entered this issue into their corrective action program as Condition Report CR-RBS-2011-02209. The licensee performed an apparent cause evaluation for this issue and determined that the 86 lockout relay associated with the circuit breaker had failed to operate due to mechanical binding in the latching mechanism, preventing the circuit breaker from tripping on overcurrent. The evaluation determined that the binding was the result of aging and a lack of relay maintenance and testing. The relay was sent to the vendor for additional forensics analysis and guidance on maintenance requirements to prevent recurrence of the failure. The vendor response identified guidance in General Electric document GEH-2058, "General Electric Instructions Auxiliary Relays Type HEA61, EA62," which recommended that this type of relay be periodically tested, including electrically tripping the relay to ensure it works and verifying that all attached circuits are complete so that the affected circuit breaker can be tripped.

The apparent cause evaluation documented industry operating experience reviews, including General Electric Service Advisory Letter 165 published in 1981 concerning HEA relay failures due to mechanical binding. The apparent cause evaluation concluded that the overall summary of external operating experience was that mechanical binding was a common cause of 86 lockout relay failures. The apparent cause evaluation documented an extent-of-condition review for the 86 lockout relay failure for relays classified as non-critical relays and run-to-failure relays; however, these relays are also installed in circuit breakers for safety-related Division III equipment.

As corrective action for the February 2011 lockout relay failure, the licensee had updated Preventive Maintenance Template E418, “Maintenance Template for HEA Relays,” to add actions to include functional testing of 86 lockout relays. The team reviewed an updated copy of this maintenance template, but could find no instances in which it had been implemented since being revised.

On May 24, 2012, an electrical fault occurred, resulting in an overcurrent condition through 13.8 kV circuit breaker NPS-SWG1B ACB028 for main feedwater pump B. Circuit Breaker ACB028 did not open to isolate the fault as expected, resulting in the trip of upstream supply breaker NPS-SWG1B ACB027. This resulted in the loss of bus NPS-SWG1B and a plant scram. The licensee’s preliminary investigation identified that circuit breaker ACB028 failed to trip due to the failure of the associated 86 lockout relay.

The team concluded the failure mode associated with the May 2012 failure appeared to be the same as the failure in February 2011. Following the May 2012 event, the licensee’s extent of condition review and testing identified nine additional failures of the older-style General Electric HEA61 relays installed in non-safety related equipment. The licensee’s investigation also determined that similar 86 lockout relays were installed in safety-related Division III equipment, but no failures were identified for these relays. The team determined that additional inspection is required to assess the effectiveness of the licensee’s corrective actions from the February 2011 event. This issue is identified as Unresolved Item URI 050000458/2012009-04, “Corrective Action Program Implementation for Prior Lockout Relay Failure in February 2011.”

2) Implementation of Vendor and Industry Recommended Relay Testing and Maintenance

Introduction. The team identified an unresolved item associated with the testing of electrical lockout relays as recommended by vendor and industry guidance. River Bend Station previously tested these relays as part of a broader program to test protective relays, but the program was discontinued.

Description. In February 2011, a General Electric Type HEA61 lockout relay had failed to function and resulted in a 13.8 kV circuit breaker failing to trip and a fire. In May 2012, a second General Electric Type HEA61 lockout relay had failed to function in the feedwater pump FWS-P1B circuit breaker resulting in an initiating event.

Following the May 2012 electrical fault involving the trip of main feedwater pump B, the licensee performed an extent-of-condition review of the 86 lockout relay population. River Bend Station used four different types of lockout relays in medium voltage circuits:

- GE HEA61 series (older style) relays
- GE HEA61 series (newer style) relays
- Electroswitch/ABB 7800 series LOR relays
- Electroswitch 422D949G56/Westinghouse WL relays

The failed relays in both the February 2011 event and the May 2012 event were identified as General Electric Type HEA61 relays. Of the two versions of Type HEA61 relays in use, the older style had failed in both events.

During the extent-of-condition review, the licensee identified that they had approximately 187 lockout relays installed in the plant. Of these, 29 relays were the older-style General Electric Type HEA61. The relays were differentiated by the type of armature used to operate the relay, where the older style had a flat plate for the armature and the newer style had an indention on the armature plate which facilitated easier mechanical operation.

During functional testing as part of the extent-of-condition testing, the licensee identified nine additional relay failures. All of the failed relays were associated with non-safety related 13.8 kV switchgear; however, the same relay type was also installed in the safety-related Division III high pressure core spray system. The licensee replaced the nine failed relays by the newer style General Electric Type HEA61 relay.

The General Electric HEA lockout relay vendor manual, GEH-2058, "General Electric Instructions Auxiliary Relays Type HEA61, HEA62," recommended that during any outage of the equipment and preferably at yearly intervals the relay should be tripped electrically to ensure that it is in good operating condition and that all the circuits are complete so that the associated circuit breakers can be tripped. The vendor manual also recommended that this electrical test be performed at 70 percent of rated voltage to ensure the device will actuate during low voltage conditions.

The team determined that, prior to 2005, the licensee had performed testing of lockout relays as part of a broader protective relay testing program. In 2004, the licensee initiated LO-RLO-2004-00146 describing, in part, a method for performing functional testing of lockout relays as part of circuit breaker testing and updating preventive maintenance task template basis documents for circuit breakers to include the lockout relays. The action initiated to combine the functional testing of relays with circuit breaker maintenance was not effectively implemented, and, as a result, the functional testing of lockout relays was discontinued.

The licensee reviewed Electroswitch Technical Publication LOR-1, "A High Speed Multi-Contact Lock-Out Relay for Power Industry Applications," effective January 1, 1980, for guidance on the Electroswitch/ABB 7800 series 24 lockout relays. This document contained no specific guidance on maintenance or recommended testing. The licensee's review identified that the lockout relays were used in safety-related Division I and II equipment and were regularly tested as part of the station's surveillance program.

The licensee provided an excerpt from Westinghouse Descriptive Bulletin 34-252, dated May 1969 as their guidance for the Westinghouse Type WL devices. The single-page document did not provide specific guidance on maintenance or recommended testing. The licensee's review identified that the WL devices were used only in non-safety related equipment.

The team identified widely used industry documents that provided generic guidance on the maintenance and testing of protective relays including Electrical Power Research Institute EPRI NP-7216s, “Protective Relay Maintenance and Application Guide,” which provided guidance for implementing a protective relay maintenance program and included descriptions of recommended electrical and functional checks.

The team assessed the licensee’s overall plan and schedule for lockout relay inspections following the May 2012 event. The team determined the plan and schedule for testing functionality of the lockout relays was appropriate as the licensee was testing all of the older style General Electric HEA61 relays, had validated functionality of other styles of lockout relays by surveillance testing the associated equipment or analysis, and would test any remaining lockout relays when plant risk conditions allowed. The team determined that the corrective actions identified were appropriate and timely, and the licensee had adequately considered safety significance in their planning process.

The team concluded that additional inspection is required to assess the lack of vendor and industry recommended maintenance activities at River Bend Station on lockout relays associated with medium voltage circuit breakers since 2005. This issue is identified as Unresolved Item URI 05000458/2012009-05, “Implementation of Vendor and Industry Recommended Relay Testing and Maintenance.”

7.0 Cable Splice Failure and Operational Decision Making (Charter Item #7)

a. Inspection Scope

The team reviewed the cause evaluations and corrective actions associated with the cable splice fire on May 21, 2012. The team evaluated the appropriateness of corrective actions for the failure and whether the extent of condition had been completely identified. The team assessed the plant configuration to determine whether the licensee’s operational decision making process had appropriately considered plant risk prior to startup following the reactor scram on May 21. As part of the assessment of operational decision making, the team observed a meeting of the licensee’s Onsite Safety Review Committee prior to startup following the reactor scram on May 24.

The team observed underground cable vault inspections and the vendor repair process for the failed cables. The team reviewed the licensee’s cable reliability program and held discussions with component engineers and maintenance personnel on cable testing and conditions.

b. Observations

The team identified two unresolved items requiring follow-up inspection associated with this charter item.

1) Implementation of the Station Cable Reliability Program

Introduction. The team identified an unresolved item associated with the licensee’s process for ensuring that underground non-safety related power cables whose failure could affect equipment in the scope of the Maintenance Rule were maintained as described in Procedure EN-DC-346, “Cable Reliability Program,” Revision 3.

Description. On May 21, 2012, non-vital 13.8 kV circuit breaker NPS-SWG1A ACB07, the supply breaker to circulating water area transformer STX-XS2A, tripped resulting in a loss of circulating water cooling to the main condenser and a subsequent reactor scram. The licensee’s investigation discovered that a fault in underground medium voltage cable 1NPSANJ322 had caused the trip of circuit breaker ACB07 and a fire in underground cable vault EMH1A. The licensee wrote Condition Report CR-RBS-2012-3440 to document the event and the root cause analysis results. The licensee’s preliminary analysis identified the most probable cause of the cable fault as moisture intrusion at a spliced connection in cable 1NPSANJ322. The team reviewed the licensee’s root cause evaluation report, dated June 19, 2012. The cause evaluation concluded that the root cause of the cable failure was poor splice crimping and water intrusion at the splice causing accelerated cable insulation degradation. The team determined the report conclusions were appropriate.

The NRC issued Generic Letter 2007-01, “Inaccessible or Underground Power Cable Failures That Disable Accident Mitigation Systems or Cause Plant Transients,” in February 2007. The generic letter required licensees to provide a description of the inspection, testing, and monitoring programs they used to detect the degradation of inaccessible or underground power cables that support systems that were within the scope of 10 CFR 50.65 (the Maintenance Rule). The Maintenance Rule required, in part, that licensees monitor the performance or condition of structures, systems, or components in a manner sufficient to provide reasonable assurance that such structures, systems, and components are capable of fulfilling their intended functions.

The team determined that the licensee had established a cable monitoring program in December 2009 and had begun diagnostic cable testing in January 2011. Procedure EN-DC-346, “Cable Reliability Program,” Revision 3, required, in part, that underground power cables whose failure could affect Maintenance Rule equipment be monitored to establish the insulation condition using appropriate testing and evaluation of the test results. The licensee identified approximately 57 in-scope cables, fourteen of which had been tested before the May 21 failure. The licensee used a dielectric loss-dissipation factor test (tan δ test) as their method of diagnosing problems in medium-voltage cables. The dielectric loss-dissipation factor test has the ability to detect thermally induced cracking, radiation-induced cracking, mechanical damage, water treeing, moisture intrusion, and surface contamination.

Following replacement of the failed cable splice, the licensee performed diagnostic testing on cables 1NPSANJ303, 1NPSANJ304, and 1NPSANJ322 as part of post-maintenance testing and identified that cable 1NPSANJ304 did not have acceptable values for insulation resistance. The licensee cut open a splice on cable 1NPSANJ304 and found water between the cable jacket and insulation. The licensee initiated Condition Report CR-RBS-2012-03590 to document the water intrusion in cable 1NPSANJ304 in the corrective action program.

The licensee's cable reliability program established a cable risk factor for setting priorities for testing shielded medium voltage cables. The cable risk factor included the number of known splices in the cable and an adverse environment risk factor for cables subject to submergence. The program also included guidance for confirming that underground cable vault maintenance practices and water level trending were sufficient to keep the cables from submergence, if possible, to increase the longevity of the insulation system. The licensee had established a risk ranking for in-scope cables, but had not inspected the in-scope underground cable vaults to determine the number and location of cable splices. The presence of splices would change the ranking of cables. Cables 1NPSANJ304 and 1NPSANJ322 had not been tested before they failed at spliced connections in May 2012. The team identified that several different ranking formats were in use at the station and concluded that the cable ranking system for the scheduling of diagnostic tests was not clearly defined.

The licensee performed visual inspections of other underground cable vaults searching for additional splices in the redundant nonsafety-related train. No additional splices were found in the redundant train; however, other underground cable vaults needed to be dewatered because the cables were submerged and were not visible until the water had been removed. The team determined that prior to performing the cable vault inspections following the May 21 cable failure, the licensee did not have the information needed to effectively implement the guidance for developing the cable risk rankings described in procedure EN-DC-346, "Cable Reliability Program," Revision 3.

The root cause evaluation report stated that a testing schedule had been developed for the remaining in-scope cables such that initial dielectric loss-dissipation factor testing would be completed for all in-scope cables by the completion of Refueling Outage 18. The licensee initiated an additional action associated with the root cause evaluation to review the risk-ranking criteria for all in-scope cables. The team concluded further inspection was required to review the effectiveness of the licensee's monitoring program for in-scope cables: Unresolved Item URI 05000458/2012009-06, "Implementation of the Station Cable Reliability Program."

(2) <u>Onsite Safety Review Committee Implementation</u>

<u>Introduction</u>. The team identified an unresolved item associated with the licensee's implementation of Procedure EN-OM-119, "Onsite Safety Review Committee," Revision 8.

<u>Description</u>. The function of the onsite safety review committee was to provide an independent review by site management personnel to assure the plant is operated and maintained in accordance with the operating license and applicable regulations. Items typically reviewed by the committee include plant modifications, procedure changes, license amendment requests, and plant restart issues following a planned or unplanned outage.

The team observed a meeting of the onsite safety review committee on May 31,2012, prior to restart of the plant following the May 24 event. The team identified several cases where the information provided to the committee members prior to the meeting was incomplete or out-of-date, or new information was provided to the committee members and evaluated during the meeting. Examples of issues observed by the team included:

- The document provided to the committee members describing the main feed pump motor failure had not been updated to reflect information gathered through discussions with the vendor and a visit to the vendor facility by River Bend personnel, or information involving inspection criteria developed during a conference call with other Entergy plants. This information was provided during the meeting and affected the conclusions in the document associated with the cause of the failure and extent of condition inspections.

- The committee members were not provided the revised version of the data package assembled using Procedure GOP-003, "Scram Recovery," Revision 22, from the May 24 scram event which had been submitted to the committee for approval.

- The document describing the results of the lockout relay failure investigation did not include information about extent-of-condition testing conducted during the two days prior to the meeting, which had included four additional relay failures.

- During the committee review of the cable splice failure, additional relevant information from ongoing extent-of-condition inspections in underground cable vaults was provided directly to the committee members for evaluation during the meeting.

- The document provided to the committee members for the reactor core isolation cooling system inadvertent isolation event on May 21 did not include information on the modification that had been developed to resolve the spurious isolation issue. The modification had already been installed in the plant. The 50.59 evaluation with associated engineering package for the installed modification was provided to the committee members for review and approval during the meeting.

- Part of the onsite safety review committee restart review included a review of issues categorized as degraded or nonconforming. The list of degraded or nonconforming conditions provided to the committee members for review had not been updated since the reactor scram on May 21. The committee directed the presenter to update the list with justification for why the items had not been completed, noting the difficulty of scheduling corrective actions in the current outage given the incremental increase in scope of the outage.

The team determined the poor quality of the information packages provided to the onsite safety review committee for review required the committee to perform or direct the work of the line organization to obtain the information. This appeared to be contrary to procedure and had the potential to hinder the effectiveness of the committee in providing an independent review function. The team considered the independent review function to be an important means to verify the effectiveness of safety-significant decisions and to clearly demonstrate nuclear safety as an overriding priority in decision-making. The team concluded additional inspection is required to assess the effectiveness of the station's implementation of the procedure for the onsite safety review committee: Unresolved Item URI 05000458/2012009-07, "Onsite Safety Review Committee Implementation."

8.0 Fire Brigade Response and Effectiveness (Charter Item #8)

a. Inspection Scope

The team reviewed the fire brigade response to the May 21 and 24 events. The review focused on the adequacy and timeliness of the fire brigade response, the fire brigade composition and staffing levels, and issues identified during the two events. The team reviewed post-fire reports, operator statements, control room logs, the fire protection program, and condition reports generated from the two events. In addition, the team interviewed members of the fire brigade that responded to these events.

b. Observations

During the May 21 event, the control room received a report of a fire in underground cable vault EMH1A at 2:57 p.m.. The fire brigade was dispatched to investigate. During their response, the fire brigade could not use the fire brigade vehicle designated for response outside the plant protected area since the vehicle battery was not functional. The licensee determined that the overhead light in the van had been left on, depleting the battery. The licensee initiated Condition Report CR-RBS-2012-03474 to address the depleted van battery. The fire brigade loaded equipment onto a security vehicle and proceeded to the vault manhole. Upon arrival at the scene, the fire brigade members used carbon dioxide extinguishers and extinguished the fire.

During the May 24 event, the control room received a report of smoke from the feedwater pump circuitry board on the 67' elevation of the Turbine Building. The fire brigade was dispatched to investigate. As described below, the fire brigade leader was unable to respond immediately to the scene to ensure staffing of the full five member fire brigade. Two of the members of the fire brigade were already on the scene since they were assisting with the startup of the feedwater pump. These fire brigade members inspected the equipment and determined that there was no indication of an active fire.

The team identified the following unresolved item associated with the fire brigade response to the May 21 and 24 events.

Introduction. The team identified an unresolved item concerning the licensee's ability to promptly staff the full fire brigade in all situations. Specifically, the team identified the potential that the full fire brigade may not be able to respond to all fires in a timely manner during times with minimum shift staffing.

Description. During the May 21 event, the outside operator, a member of the fire brigade, was dispatched to the river to assist with flume control after the scram. Subsequent to the operator's departure, the fire brigade was dispatched to investigate the fire in underground cable vault EMH1A. Because of the post-scram duties at the river, the outside operator was unable to respond to the fire in a timely fashion.

During the May 21 event, the auxiliary control room operator also served as a member of the fire brigade. The conduct of operations procedure provided instructions for the auxiliary control room operator to abandon the auxiliary control room in the event the only operator present was required for the fire brigade. This procedure required that the auxiliary control room operator take several steps to secure equipment prior to abandoning the auxiliary control room. During interviews with the inspection team, operators indicated that these actions could take up to 20 minutes to complete.

During the fire response on May 21, the licensee was able to utilize additional operators in their response. Specifically, the licensee utilized another qualified operator as a fire brigade member in lieu of the assigned outside operator. In addition, an additional operator was available to relieve the auxiliary control room operator so the auxiliary control room operator could leave to serve as a fire brigade member without abandoning the auxiliary control room. The team noted that the May 21 event occurred during the day shift when additional operators were present, and that the additional operators may not be present during the night shift or any time with minimum shift staffing.

On May 24, prior to the event, the fire brigade leader was selected to take a random fitness for duty test. While the leader was waiting to take the test, the fire brigade was dispatched to respond to the fire event. The fire brigade leader was informed that leaving the fitness for duty testing area would be considered the same as failing to take the fitness for duty test. In the meantime, the other four fire brigade members responded to the fire. Two of the members responded to the fire brigade locker, while the other two fire brigade members, who were already located near the fire, remained near the feedwater pump to observe the conditions. During this time, one of the fire brigade members, who was also qualified as a fire brigade leader, served as a temporary fire brigade leader and maintained communication with the control room.

Upon returning from the fitness for duty test, the fire brigade leader assumed the role of fire brigade leader for this event. By this time, the only remaining activities involved establishing a fire watch and disbanding the fire brigade. For this event, the team noted that no additional qualified fire brigade members responded to the fire, and the fire response consisted of the four assigned fire brigade members.

Based on this event, the team identified a potential vulnerability in that the licensee did not have a formal process for operators to turn over their fire brigade responsibilities in the event their duties removed from the immediate area of the plant. Specifically, the team identified that the licensee did not have provisions for operators to respond to events if they were selected for a fitness for duty test, nor did they have provisions to ensure that alternate fire brigade members could be provided if one of the assigned fire brigade members was unable to perform their fire brigade function for any reason.

This item is considered unresolved pending additional inspection of the approved fire protection program: Unresolved Item URI 05000458/2012009-08, “Ability to Promptly Staff the Fire Brigade at All Times During Plant Operation.”

9.0 Past Maintenance Impact (Charter Item #9)

a. Inspection Scope

The team conducted an overall review of the licensee’s maintenance practices to determine if past maintenance activities could have contributed to the event or impacted the response and recovery. The team reviewed the sequence of events to determine which components did not perform as expected or performed poorly to determine the systems on which to focus. The team also reviewed the updated final safety analysis report, technical specifications, system health reports, quality audits, design basis documents, condition reports, and interviewed personnel to verify that appropriate performance criteria were being monitored and maintained.

b. Observations

The team determined that past maintenance practices caused or contributed to many of the issues involved with the loss of normal service water event. Section 5.0 of this report describes the fault in the main feedwater pump motor which was the initiating event for the loss of normal service water and reactor scram. The loose connection the licensee identified as the cause of the fault involved maintenance practices during the installation of the pump motor. Section 6.0 of this report discusses the failure of the main feedwater pump motor breaker to isolate the electrical fault. The breaker did not open due to a failed lockout relay. The licensee had not been performing the vendor recommended functional testing for lockout relays prior to the failure on May 24.

The team concluded that preventive maintenance and equipment health monitoring programs intended to prevent failures at the station were not effective to prevent the May 24 event. The team noted that the station thermography program had failed to identify the loose connections associated with the main feedwater pump motor. The team determined that the thermographic inspections at the station were performed on rotating building basis, in which the available equipment in a given building would be checked when that building was scheduled for testing. Using this testing schedule, the common practice of performing maintenance on one train of redundant equipment during a given week and protecting the opposite train could cause the thermography testing to be missed on the protected train equipment. The licensee identified this same vulnerability in the station vibration monitoring program, and initiated a root cause analysis for significantly overdue vibration monitoring data as part of associated Condition Report CR-RBS-2012-02983.

Section 7.0 of this report discusses the cable splice failure which was the cause of the reactor scram event on May 21, 2012. The team determined the station cable reliability program had not been effective in establishing the baseline conditions of underground cables. This information would be needed to develop an effective schedule for prioritizing testing for monitoring cable health. The team reviewed the licensee's Generic Letter 2007-01 response dated May 3, 2007, in which the licensee stated that underground cable reliability would be monitored through the corrective action program. The team considered that this response could be reflective of an emphasis on corrective maintenance rather than preventive maintenance.

The team also identified that considerable industry operating experience was available to the licensee associated with the equipment issues discussed in this report. The team noted operating experience existed associated with spurious isolations of the reactor core isolation cooling system, leakage from safety relief valves following use during cooldown operations, and lockout relays, which were the subject of a Service Advisory Letter from the manufacturer and numerous failures at other facilities. The use of industry operating experience is an effective tool for informing preventive and predictive maintenance programs to prevent equipment failures.

The team did not identify any issues for additional inspection specifically associated with this charter item.

10.0 Independent Risk Assessment (Charter Item #10)

a. Inspection Scope

The team reviewed the sequence of events and equipment problems to support an independent assessment of the risk of the reactor scram with loss of normal service water event.

b. Observations

NRC senior reactor analysts originally estimated the risk from the May 24 loss of normal service water and reactor scram event using the River Bend Station site-specific Standardization Plant Analysis Risk (SPAR) model, Revision 8.17. The resulting conditional core damage probability was 1.2E-4, which was in the range for an augmented inspection team using Management Directive 8.3, "NRC Incident Investigation Program." The dominant contributors to the risk significance of the event involved the potential for failures of the safety-related standby service water system and combinations of failures of the standby service water system and its supported components. Based on their review of the sequence of events and discussions with operators, the team concluded the risk assumptions used by the senior reactor analysts to model the event were appropriate.

The senior reactor analysts subsequently discovered an error in the River Bend Station SPAR model in which the model was inappropriately double-counting many of the dominant cutsets. The senior reactor analysts requested and received a corrected version of the SPAR model from the Idaho National Laboratory. The revised conditional core damage probability using the new model for the River Bend loss of normal service water event was 6.3E-5, placing the risk in the overlap region for a special inspection and an augmented inspection team.

11.0 Quality Assurance, Radiological Controls, Security, and Safety Culture Aspects (Charter Item #11)

a. Inspection Scope

The team reviewed the sequence of events, operator actions, management decisions, and equipment problems to determine whether issues existed related to quality assurance, radiological controls, security, and safety culture.

b. Observations

The team did not identify any issues associated with quality assurance, radiological controls, or security. With regard to safety culture, the team noted that many of the issues identified for follow up inspection in this report could potentially be related to safety culture aspects described in Manual Chapter 0310, “Components Within the Cross-Cutting Areas,” associated with the components of Decision-Making in the area of Human Performance and with the Corrective Action Program in the area of Problem Identification and Resolution.

The team did not identify any issues for additional inspection specifically associated with this charter item.

12.0 Exit Meeting Summary

On July 11, 2012, the NRC held a public meeting and presented the inspection results to Mr. E. Olson and other members of the staff, who acknowledged the observations. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

J. Adams, Operations
C. Bailey, Components Engineer – Electrical
R. Beaucharp, Shift Manager
D. Bottemiller, Manager (acting), Licensing
S. Carter, Shift Manager
J. Clark, Manager, Licensing
F. Colaricci, Nuclear Control Room Supervisor
C. Colclough, Operations
A. Cruze, Control Room Supervisor
D. Dabadie, Control Room Supervisor
J. Dukocics, Reactor Engineer
T. Evans, Operations Manager
E. Enfinger, Nuclear Control Room Operator
M. Feltner, Manager, Planning and Scheduling, Outages
C. Forpahl, Manager, System Engineering
J. Fortenberry, Operations
A. Fredieu, Manager, Outage
J. Fralic, Superintendent, Licensed Operator Requalification Training
R. Gadbois, General Manager, Plant Operations
T. Gates, Assistant Operations Manager – Shift
T. Glass, In-Service Test Engineer
H. Goodman, Director, Engineering
C. Gravois, Engineer, Electrical and I&C Systems
D. Hall, Operations
G. Hendl, Safety Relief Valve Engineer
K. Jelks, Supervisor, Electrical Engineering
K. Huffstatler, Senior Licensing Specialist
R. Karner, Operations
J. Kelley, Operations
C. Keown, Operations
G. Krause, Assistant Operations Manager – Support
O. McClure, Operations
J. Meyer, Supervisor, BOP Systems
C. Miller, Project Manager
E. Olson, Site Vice President
D. Pipkin, Shift Manager
S. Riley, Operations
J. Roberts, Director, Nuclear Safety Assurance
A. Seward, Nuclear Control Room Supervisor
D. Thomas, Control Room Supervisor
T. Watkins, Supervisor (Acting), Engineering FIN Team

Z. Wetzel, Operations
D. White, Component Engineer
D. Williamson, Sr. Licensing Specialist
D. Wilson, Control Room Supervisor

NRC Personnel

Grant Larkin, Senior Resident Inspector
Andy Barrett, Resident Inspector
Alan Wang, Project Manager, NRR

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000458/2012009-01	URI	Main Control Room Annunciator Control and Conduct of Operations (Section 2.b.1)
05000458/2012009-02	URI	Past Operability of the Reactor Core Isolation Cooling System (Section 2.b.2)
05000458/2012009-03	URI	Implementation of the Procedure for Infrequently Performed Tests or Evolutions (Section 3.b)
05000458/2012009-04	URI	Corrective Action Program Implementation for Prior Lockout Relay Failure in February 2011 (Section 6.b.1)
05000458/2012009-05	URI	Implementation of Vendor and Industry Recommended Relay Testing and Maintenance (Section 6.b.2)
05000458/2012009-06	URI	Implementation of the Station Cable Reliability Program (Section 7.b.1)
05000458/2012009-07	URI	Onsite Safety Review Committee Implementation (Section 7.b.2)
05000458/2012009-08	URI	Ability to Promptly Staff the Fire Brigade at All Times During Plant Operation (Section 8.b)

LIST OF DOCUMENTS REVIEWED

CONDITION REPORTS (CR-RBS-)

2010-06417	2012-03524	2012-03572	2012-03629	2012-03687
2011-02209	2012-03527	2012-03573	2012-03642	2012-03686
2012-02626	2012-03532	2012-03579	2012-03644	2012-03699
2012-02951	2012-03533	2012-03582	2012-03646	2012-03705
2012-02983	2012-03534	2012-03583	2012-03649	2012-03706
2012-03302	2012-03535	2012-03584	2012-03650	2012-03897
2012-03380	2012-03544	2012-03590	2012-03651	2012-03925
2012-03428	2012-03546	2012-03611	2012-03662	2012-03929
2012-03429	2012-03555	2012-03614	2012-03665	2012-03941
2012-03438	2012-03559	2012-03615	2012-03667	
2012-03439	2012-03561	2012-03619	2012-03668	LO-RLO-2004-00146
2012-03474	2012-03568	2012-03622	2012-03817	

DRAWINGS

Number	Title	Revision
0126D9589	Indoor M36HN Metalclad Switchgear	B
0138D3298	Metalclad Switchgear Connection Diagram	A
0258A1822	13.8 kV Indoor Metalclad Switchgear Bill of Material 1NPS-SWG1B	10
12210-EE-32K-6	Arrangement – Manholes Plan and Details	6
12210-EE-32N-4	Arrangement – Manholes Plan and Details	4
12210-EE-32R-5	Arrangement – Manholes Plan and Details	5
12210-ESK-7FWS01	Elementary Diagram – 120V Control Circuit Reactor Feedwater Pumps Auxiliary Control	8
131C149	Outline – Induction Motor (Feedwater Pump)	F
EE-001AC	Start Up Electrical Distribution Chart	42
EE-001AC	Start Up Electrical Distribution Chart	45
EE-001E	13.8 kV One Line Diagram Bus 1NPS-SWG1B	13
EE-042F	Conduit Plan and Details Normal Switchgear Building EL. 98’ – 0”	8
EE-08G	13.8 kV Wiring Diagram Bus 1NPS-SWG1B	15

Number	Title	Revision
EE-32B-13	Arrangement – Ductline and Plans	13
EE-32J-7	Arrangement – Manholes Plan and Details	7
ESK-05FWS01	Elementary Diagram – 13.8 kV Switchgear Reactor Feedwater Pump 1A Supply ACB 12	15
ESK-05FWS02	Elementary Diagram – 13.8 kV Switchgear Reactor Feedwater Pump 1B Supply ACB 28	15
ESK-05NNS06	Elementary Diagram – 4.16 kV Switchgear Bus 1B Preferred Supply ACB	19
ESK-05NPS02	Elementary Diagram – 13.8 kV Switchgear Bus 1B Normal Supply ACB	15
ESK-05NPS04	Elementary Diagram – 13.8 kV Switchgear Bus 1B Preferred Supply ACB	16
ESK-08SPG04	Elementary Diagram – 125V Control Circuit Generator Primary Protection	12
ESK-08SPR06	Elementary Diagram – 125V Control Circuit Preferred Station Service Primary Protection	16
ESK-08SPR06	Elementary Diagram – 125VDC Control Circuit Preferred Station Service Transformer Back-Up Protection	24
ESK-08SPU03	Elementary Diagram – 125VDC Control Circuit Transformer Sudden Pressure Protection	19
ESK-08SPU04	D. C. Elementary Diagram – Unit Protection	9
ESK-11SPF02	Elementary Diagram – Station Protection Reserve Station Service Line	8
GE-828E232AA	Elementary Diagram Feedwater Control System	26

ENGINEERING REQUESTS (ER)

Number	Title	Revision
ER-RB-2006-0075-000	Electric Machinery Storage Requirements for 8000HP Feedwater Pump Motor	0

CALCULATIONS

Number	Title	Revision
GEZ-7357	River Bend Station Transient Safety Analysis Design Report	03/1985

MISCELLANEOUS DOCUMENTS

Number	Title	Revision/Date
	Entergy Quality Assurance Program Manual	22
	86 Lockout Relays – Whitepaper and Attachments	May, 2012
	RBS Protective Relays – Lock-Out Relay Maintenance Template (Rev. 0)	December 8, 2006
	Run-To-Failure 86 Relays (Spreadsheet)	May, 2012
	Cables in Manhole 1EMH1A (Spreadsheet)	June, 2012
	Cable Trending Data (Spreadsheet) for Cables Tested by Program to Date	May, 2012
	NNS-SWG2A Cable Failure CR-RBS-2012-3440 Whitepaper	May, 2012
	Letter from NRC to Vice President, Nuclear Operations, Entergy Operations, Inc. SUBJ: Closeout of Generic Letter 2007-01, “Inaccessible or Underground Power Cable Failures That Disable Accident Mitigation Systems or Cause Plant Transients (TAC No. MD4371)	October 24, 2008
	Manhole Performance Monitoring Spreadsheet	May, 2012
	River Bend Critical Manholes Spreadsheet	May, 2012
	Cables in Manhole 36 Spreadsheet	June, 2012
	Large Motor Work History (Spreadsheet)	May, 2012
	Motor Repair / Refurbishment / Rewind Report for Entergy – River Bend Nuclear Station 8000 HP Reactor Feed Water Pump Motor	
	Motor Testing Results from Baker Testing Suite for Feedwater Pump Motors FWS-P1A, -P1B, and –P1C	2008 2009 2011
	White Papers for May 31 OSRC Meeting	May, 2012
240.000	Electrical Installation Specifications	10
241.232	Addendum 1 and Specification for Insulated 15 kV and 5 kV Power Cable	0

Number	Title	Revision/Date
244.401	Specification for Large Horizontal 4 kV and 13.2 kV Alternating Current Induction Motors thru Addendum 5	
3241.232-122-001A	Cable Installation Manual, 3rd Edition – Anaconda Ericsson PC-7600-3	1981
CR-RBS-2011-2209	Station NJS-X2C Transformer Bus Faulted Causing Significant Bus, Cable, and Switchgear Damage	NA
E418	Maintenance Template for HEA Relays	May 3, 2012
E418A	Maintenance Template for HEA Relays	December 29, 2010
EC37843	Add Time Delay to E31-PDTN084A/B	Revision 0
HVA TD Report Summary for Cable 1NPSANJ303	Tan-Delta Testing Summary for Cable 1NPSANJ303, B and C Phase	May 25, 2012
HVA TD Report Summary for Cable 1NPSANJ304	Tan-Delta Testing Summary for Cable 1NPSANJ304, B and C Phase (Before Repairs)	May 25, 2012
HVA TD Report Summary for Cable 1NPSANJ304	Tan-Delta Testing Summary for Cable 1NPSANJ304, B and C Phase (After Repairs)	May 26, 2012
HVA TD Report Summary for Cable 1NPSANJ322	Tan-Delta Testing Summary for Cable 1NPSANJ322, B and C Phase	May 26, 2012
RBF1-07-0070	Response to Generic Letter 2007-01 River Bend Station – Unit 1 Docket No. 50-458 License Number NPF-47	May 3, 2007
SDC-301 (NPS) / 302(NNS)	Non-Safety Related 13.8 and 4.16 kV Electrical Distribution System Design Criteria System Number 301 and 302	2
NRC Generic Letter 2007-01	Inaccessible or Underground Power Cable Failures That Disable Accident Mitigation Systems or Cause Plant Transients	February 7, 2007
RBF1-07-0070	Letter from River Bend Station, Unit 1, to NRC; Subject: Response to Generic Letter 2007-01	May 3, 2007
	Post Fire Report	05/21/2012
	Post Fire Report	05/24/2012
	Post Scram Report	05/21/2012

Number	Title	Revision/Date
	Post Scram Report	05/24/2012
	Control Room Log (05/18/2012 to 05/28/2012)	
	Outage Control Center Log (05/21/2012 to 05/28/2012)	
	Sequence of Events Log	05/24/2012

PROCEDURES

Number	Title	Revision
ADM-0096	Risk Management Program Implementation and On-Line Risk Management	312
AOP-0001	Reactor Scram	25
AOP-0002	Main Turbine and Generator Trip	24
AOP-0003	Automatic Isolations	29
AOP-0005	Loss of Main Condenser Vacuum/Trip of Circulating Water Pump	21
AOP-0009	Loss of Normal Service Water	20
AOP-0010	Loss of One Reactor Protection Bus	29
AOP-0011	Loss of Plant Component Cooling Water	18
AOP-0012	Loss of Turbine Plant Component Cooling Water	12
AOP-0035	Safety Relief Valve Stuck Open	17
CMP-1277	Lugging, Splicing and Termination of Power, Control and Instrument Cable	12
EN-DC-330	Fire Protection Program	1
EN-DC-344	Large Motor Program	1
EN-DC-346	Cable Reliability Program	3
EN-NS-102	Fitness for Duty Program	9
EN-OM-119	On-Site Safety Review Committee	8
EN-OP-116	Infrequently Performed Tests or Evolutions	9
EOP-1	RPV Control	25

Number	Title	Revision
EOP-2	Primary Containment Control	14
EOP-5, Enclosure 12	Defeating Reactor Protection System and Alternate Rod Insertion Logic Trips	311
EOP-5, Enclosure 16	Defeating Containment Instrument Air Isolation Interlocks	311
EOP-5, Enclosure 2	Defeating RCIC Low RPV Pressure Isolation Interlock	311
EOP-5, Enclosure 3	Defeating RCIC High Suppression Pool Water Level Suction Transfer Interlock	311
EOP-5, Enclosure 33	Defeating RCIC High Area Temperature Isolation Interlocks	311
GOP-0001	Plant Startup	69
GOP-0001	Plant Startup	70
GOP-0003	Scram Recovery	22
None	Operations Standards and Expectations	38
OSP-0022	Operations General Administrative Guidelines	48
SEP-FPP-RBS-001	Fire Protection Program	0
SEP-FPP-RBS-002	Fire Fighting Procedure	1

VENDOR MANUALS

Number	Title	Revision/Date
LOR-1	A High Speed Multi-Contact Lock-Out Relay for Power Industry Applications	January 1, 1980
VTD-G080-0144	General Electric Instructions Auxiliary Relays Hand Reset with Target Type HEA61, HEA62	0
3242.520-100-002A	Instruction Manual – 4.16 Switchgear 1NNS-SWG (Page 253 – Switches Type WL)	301
VTD-E120-0100	Instruction Manual E-M Induction Motors for Reactor Feed Pump Drives	00
HVS-1520S	15kV Class Splice for Extruded Dielectric (Poly/EPR) Power Cables: Metallic Tape, Wire Shield, Unishield, or Lead Sheath Cables	April 28, 2006

WORK ORDERS

315783	316257	316296-01	315925
316336-01	315750	316296-02	

Attachment 2: SEQUENCE OF EVENTS

Date/Time	Event Description
May 21, 2012	
14:51:40	Alarm H13-P808/86A/A08, “NPS-SWG1A Dist Brkr Auto Tripped,” was received
14:51:40	Panel H13-P808 indicated breaker NPS-ACB07, “Circ Water Area Brkr,” tripped
14:52:00	Automatic reactor scram due to turbine trip on low condenser vacuum
14:57:28	Main control room received report of a fire in manhole EMH1A
14:59:21	Fire brigade dispatched to investigate
15:11:54	Fire brigade discharged portable fire extinguishers and reported to control room that they believed the fire was out, but they were waiting for the smoke to clear
15:15:56	The fire in manhole EMH1A was declared out
May 22, 2012	
16:02:42	Busses NNS-SWG2A and NNS-SWG2B were cross-tied
May 23, 2012	
00:08	Reactor mode switch placed in STARTUP
04:11	Reactor was declared critical
23:01	Reactor mode switch placed in RUN
23:01	Reactor entered Mode 1

May 24, 2012

13:48	Manual reactor scram due to the loss of all feedwater and circulating water pumps
13:48	Operators implemented procedure EOP-1, “Reactor Pressure Vessel Control,” on low reactor pressure vessel level and procedure EOP-3, “Secondary Containment and Radioactivity Release Control,” on high annulus pressure
13:48	Reactor core isolation cooling manually initiated for level control per procedure EOP-1
13:50	Main control room received a report that FWS-P1B circuitry board was smoking on the Turbine Building 67' elevation. Fire brigade dispatched to investigate
13:58	Main control room received a report that smoke was dissipating on the Turbine Building 67' elevation, there was physical damage to the connection box, but no visible fire
14:00	Main control room received a report that there was no visible damage to NPS-SWG1B, but there was a burning smell throughout the normal switchgear building
14:05	Fire brigade reported no casualties or injuries and no fire outside of circuitry board
14:05	Operators closed outboard main steam isolation valves
14:12	Residual heat removal pump A was placed in suppression pool cooling
14:14	Fire brigade reported no indication of fire and noted charring of wires in FWS-P1B circuitry panel
14:20	Fire brigade reported the T4 cable to the motor of FWS-P1B was melted
14:30	Operators closed inboard main steam isolation valves
14:32	Main control room received a report that the feeder breaker for FWS-P1B indicated an 86 device tripped and a coil burnt at the breaker cubicle
14:35	Operators entered EOP-2, “Primary Containment Control,” on high containment pressure
14:46	Containment vented with standby gas trains

14:52	Service water aligned to containment unit coolers
14:54	Fire brigade disbanded
15:01	High pressure core spray pump started manually to assist with level control if needed
15:01	Busses NJS-LDC1A/1B and NJS-LDC1A were cross-tied
15:07	High pressure core spray pump secured
15:22	Busses NJS-LDC1N/1P and NJS-LDC1N were cross-tied
15:24	Busses NJS-LDC1S/1T and NJS-LDC1S were cross-tied
15:25	Busses NJS-LDC1Q/1R and NJS-LDC1Q were cross-tied
15:29	Busses NJS-LDC1G/1H and NJS-LDC1G were cross-tied
15:33	Busses NJS-LDC1E/1F and NJS-LDC1E were cross-tied
15:34	Reactor water level reached Level 8 during safety relief valve operation to lower reactor pressure. Reactor core isolation cooling automatically shutdown on Level 8 signal.
15:35	Busses NJS-LDC1U/1V and NJS-LDC1U were cross-tied
15:38	Busses NJS-LDC1C/1D and NJS-LDC1C were cross-tied
15:39	Second Level 8 signal received
15:45	Reactor core isolation cooling was restarted after level lowered below Level 8 when the safety relief valve was closed
15:47	Busses NJS-LDC1L/1M and NJS-LDC1L were cross-tied
15:50	Residual heat removal pump B was placed in suppression pool cooling
15:53	Main control room received a report that the NPS-SWG1B ACB28 86 device was tripped and the trip coil was burned
15:55	Busses NJS-LDC3C/3D and NJS-LDC3C were cross-tied

17:06	Busses NJS-LDC1J/1K and NJS-LDC1J were cross-tied
17:32	Residual heat removal pump A was secured from suppression pool cooling
23:48	Residual heat removal pump A was placed in suppression pool cooling

May 25, 2012

00:12	Operators exited EOP-001, EOP-002, and EOP-003
01:14	Reactor core isolation cooling was isolated
02:00	Reactor entered Mode 4

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

May 30, 2012

MEMORANDUM TO: Geoffrey Miller, Chief, Engineering Branch 2
Division of Reactor Safety

FROM: Elmo E. Collins, Regional Administrator ***/AVEGEL for/***
Region IV

SUBJECT: AUGMENTED INSPECTION TEAM CHARTER TO EVALUATE THE SCRAM WITH LOSS OF SERVICE WATER EVENT AT RIVER BEND STATION

You have been selected to lead an Augmented Inspection Team to assess the circumstances surrounding the electrical fault resulting in the complete loss of service water and reactor scram event on May 24, 2012. The following are the other team members.

- Sam Graves (Region IV)
- Steve Garchow (Region IV)
- Steve Alferink (Region IV)

A. Basis

On May 24, 2012, operators at River Bend Station manually scrammed the reactor while at 33% reactor power. The reactor scram was the result of a loss of circulating water and nonsafety-related cooling water caused by a fault located in the main feedwater pump 1B motor termination box. The fault was not isolated by the motor feeder breaker due to a mechanically bound breaker 86 lockout relay. The fire brigade was dispatched to the 1B feedwater pump (FWS-PIB), and to the normal switchgear building on the report of smoke and an acrid smell caused by the 86 lockout relay coil. No fires were noted.

The supply breaker NPS-1B for the 13.8 kV nonsafety-related bus tripped to clear the FWS-P1B fault. Because of a previous cable failure and fire on Monday, May 21, 2012, all operating circulating water pumps and normal service water pumps were powered through this breaker. The loss of the running pumps resulted in the loss of condenser vacuum and cooling water to all turbine building and safety-related loads. Both divisions of safety-related standby service water system started to restore cooling to the safety-related loads.

Plant personnel are continuing to investigate the cause of the failure and determine necessary repairs. The plant is in a safe condition in cold shutdown for scram recovery maintenance, and power has been restored to the nonsafety-related loads. All three safety-related electrical buses remain energized from offsite power, and all three diesel generators are operable. No emergency action level declaration was made, and there were no radiological releases due to this event.

In accordance with Management Directive 8.3, “NRC Incident Investigation Program,” deterministic and conditional risk criteria were used to evaluate the level of NRC response for this operational event. This event met three deterministic criteria and conditional large early release probability for additional follow-up inspection. The initial risk assessment, while subject to some uncertainties, indicates that the conditional core damage probability for the event is in the range for an augmented inspection. Region IV, in consultation with the Office of Nuclear Reactor Regulation (NRR), concluded that the NRC response should be an augmented inspection team.

This augmented inspection is chartered to identify the circumstances surrounding this event, review the licensee’s actions following discovery of the conditions, and evaluate the responses of plant equipment and the licensee to the event.

B. Scope

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

1. Develop an event chronology of significant events during the loss of cooling water and the scram, the subsequent cooldown, recovery efforts, and troubleshooting/cause analysis. This should include identifying the conditions preceding the event, system responses, and equipment performance.

2. Assess licensee actions taken in response to the event, actions to cool the plant down, and actions performed during recovery of plant systems, other operator actions, and event classification and reporting. Include in this review an assessment of the operation of the reactor core isolation cooling system.

3. Assess procedure use and adequacy for this event.

4. Assess whether plant systems responded as expected. Compare the actual plant response to the applicable safety analyses.

5. Assess the licensee’s efforts to identify the source of the fault in main feedwater pump FWS-P1B. Evaluate the licensee’s corrective actions for appropriateness to correct the identified cause and extent of condition for the fault.

6. Assess the licensee’s efforts to identify the cause of the 86 lockout relay failure on the main feedwater pump breaker. Evaluate the extent of condition for the failure mode, including whether this failure is related to a similar failure of the 86 lockout relay for circulating water cooling tower C on February 12, 2011. Assess the licensee’s overall plan and schedule for lockout relay inspections to determine whether the corrective actions identified are appropriate and timely, and whether the licensee adequately considered safety significance.

7. Assess the cause evaluation and corrective actions associated with the cable splice fire on May 21, 2012. Evaluate whether the corrective actions are appropriate for the cause of the failure and whether the extent of condition has been completely identified. Assess the plant configuration to determine whether the licensee's operational decision making process appropriately considered plant risk prior to startup following the reactor scram on May 21.

8. Assess the effectiveness of fire brigade response to the May 21 and 24 events.

9. Assess whether past maintenance-related activities could have contributed to the event, or impacted the response and recovery.

10. Collect data to support an independent assessment of the risk significance of the event.

11. Assess the results of the charter items above to determine whether there were issues with quality assurance, radiological controls, security or safeguards, or safety culture components.

C. Guidance

Remaining team members will report to the site on May 29 and join the two team members already on site reviewing the licensee's preparations for reactor restart. Inspection Procedure 93800, "Augmented Team Inspection" provides additional guidance to be used during the conduct of the inspection. Your duties will be as described in this procedure and should emphasize fact-finding in the review of the circumstances surrounding the event. It is not the responsibility of the team to examine the regulatory process. The team should notify Region IV management of any potential generic issues identified related to this event for discussion with NRR. Safety or security concerns identified that are not directly related to the event should be reported to the Region IV office for appropriate action.

It is anticipated that the on-site portion of the inspection will be completed by June 8, 2012. You should provide a recommendation concerning when the onsite inspection should be concluded after you are on site.

An initial briefing of Region IV management will be provided on May 28, 2012, with daily briefings thereafter. In accordance with Inspection Procedure 93800, you should promptly recommend a change in inspection scope or escalation if information indicates that the assumptions used in the MD 8.3 risk analysis were incorrect.

A report documenting the results of the inspection should be issued within 30 days of the completion of the inspection. The report should address all applicable areas specified in Section 03.02 of Inspection Procedure 93800. At the completion of the inspection, you should provide recommendations for improving the Reactor Oversight Process baseline inspection procedures and augmented inspection process based on any lessons learned, as well as recommendations for generic communications.