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

February 14, 2005

Paul D. Hinnenkamp
Vice President - Operations
Entergy Operations, Inc.
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St. Francisville, LA 70775

SUBJECT: RIVER BEND STATION - NRC INTEGRATED INSPECTION REPORT 05000458/2004005

Dear Mr. Hinnenkamp:

On December 31, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your River Bend Station. The enclosed integrated inspection report documents the inspection findings, which were discussed on January 4, 2005, with you and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents eight findings of very low safety significance (Green), evaluated under the risk significance determination process. Six of these findings were determined to involve a violation of NRC requirements. However, because of the very low safety significance (Green) and because they were entered into your corrective action program, the NRC is treating these findings as noncited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy, NUREG-1600. If you contest these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at River Bend Station.

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 document system (ADAMS). ADAMS is accessible from the NRC web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

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

Sincerely,

/RA/

David N. Graves, Chief
Project Branch B
Division of Reactor Projects

Docket: 50-458
License: NPF-47

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NRC Inspection Report 05000458/2004005
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-458
License:	NPF-47
Report:	05000458/2004005
Licensee:	Entergy Operations, Inc.
Facility:	River Bend Station
Location:	5485 U.S. Highway 61 St. Francisville, Louisiana
Dates:	October 1 through December 31, 2004
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	M. O. Miller, Resident Inspector, Project Branch B
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Approved By:	D. N. Graves, Chief Project Branch B Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000458/2004005; 10/01/2004 - 12/31/2004; River Bend Station; Inservice Insp Activities, Pers Perf During Nonroutine Plant Evol, Refueling & Other Outage Activity, Access Control to Rad Sig Areas, Ident & Res of Prob, Event Followup, Other Activities

The report covered a 3-month period of routine baseline inspections by resident inspectors and announced inspections by regional engineering and maintenance and radiation protection inspectors. Six Green noncited violations (NCV) and two Green findings were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a green noncited violation of Technical Specification 5.4.1.a for failure to make a proper change to the tagging boundary around balance of plant Transformer RTX-XSR1F during Refueling Outage 12. This performance deficiency resulted in a trip signal, generated during troubleshooting the transformer sudden overpressure protection circuit, which caused the trip of switchyard Breakers OCB-20670 and OCB-20665. This resulted in the loss of offsite power to Division II engineered safety features Transformer RTX-XSR1D, causing a loss of shutdown cooling, a loss of alternate decay heat removal, containment isolations, and an automatic start of the Division II emergency diesel generator.

  The inspectors determined that this human performance error was more than minor because it was associated with the initiating event cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations. The inspectors evaluated the finding using IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process," and determined that the loss of offsite power to Division II engineered safety features switchgear was of very low safety significance because there was no increased likelihood of a loss of reactor coolant system inventory, there was no loss of reactor water level instrumentation, there was no degradation of the licensee's ability to terminate a leak path or add water to the reactor when needed, nor was there any degradation of the licensee's ability to recover decay heat removal once it was lost. Because this human performance error was of very low safety significance (Green) and was documented in the licensee's corrective action program as CR-RBS-2003-03456, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy, NUREG-1600 (Section 1R20).

- Green. The inspectors identified a self-revealing noncited violation of Technical Specification 5.4.1.a. that was of very low safety significance (Green). As a result, during preparation for Division I integrated emergency core cooling systems testing, a technician inadvertently made contact with the wrong terminal on an undervoltage relay which tripped the preferred offsite power feeder breaker for the Division I safety-related 4160 Vac switchgear and started the Division I emergency diesel generator.

The inspectors determined that the inadvertent contact of the wrong terminal on Division I was a performance deficiency and a human performance error. Also, ineffective and incomplete corrective actions for similar errors contributed to the performance deficiency. The finding was more than minor because it was associated with the initiating events cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions, namely a partial loss of offsite power. The inspectors evaluated the finding using Inspection Manual Chapter 0609, Appendix G, "Shutdown Operations Significant Determination Process," Attachment 1, Checklist 7, "BWR Refueling Operations with RCS Level greater than 23 feet." The finding was of very low safety significance (Green) because it did not cause a loss of shutdown cooling and did not compromise the ac power guidelines that: (1) one qualified circuit of offsite power remain operable; (2) at least one emergency diesel generator remain operable; and (3) necessary portions of the ac electrical power distribution systems remain operable.

The inspectors determined that this human performance error with problem identification and resolution aspects was the result of a violation of Technical Specification 5.4.1.a. which states, in part, that procedures shall be implemented and maintained as recommended in NUREG 1.33, Revision 2, Appendix A. Section 9.e. refers to general procedures for the control of maintenance activities. The licensee failed to evaluate the applicability of error reduction techniques, such as "taping of adjacent leads/contact points," for the installation of jumpers during Division I integrated emergency core cooling system testing, Procedure STP-309-0603, in accordance with Procedure ADM-0023, "Conduct of Maintenance," Revision 17A, Section 8.5. In addition, the licensee failed to install banana jacks on terminals on the back of the undervoltage relay in the Division I safety-related 4160 Vac switchgear, which were jumpered during the performance of Procedure STP-309-0603, in accordance with Procedure EDS-EE-001, "Banana Jack Standard," Revision 3. Because the finding was of very low safety significance and was entered into the licensee's corrective action program as Condition Report CR-RBS-2004-3518, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy, NUREG-1600 (Section 4OA2).

- <u>Green</u>. The inspectors identified a finding based on the licensee's failure to adequately identify the root cause of the April 21, 2001, turbine trip and reactor scram so as to prevent recurrence. This failure resulted in a subsequent turbine trip and reactor scram on September 22, 2003.

  The inspectors determined that the failure by the licensee to adequately identify the root cause of the April 21, 2001, event and to take effective corrective actions to prevent electrostatic arcing from affecting the primary and backup speed probes, was a performance deficiency. The inspectors determined that this performance deficiency led directly to the recurrence of the event on September 22, 2003. The finding was more than minor because it was associated with the equipment performance attribute of the initiating events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The inspectors reviewed the finding using Inspection Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." Based on the the Phase 1 screening of the finding, the inspectors determined that the finding was of very low safety significance because it did not affect loss of coolant accident initiators, did not contribute to increasing the likelihood of both an initiating event and affect mitigating equipment, and did not increase the likelihood of a fire or flood. This finding had problem identification and resolution crosscutting aspects regarding ineffective root cause determinations (evaluation). It was entered into the licensee's corrective action program as Condition Report CR-RBS-2003-3203 (Section 4OA3).

- Green. The inspectors identified a self-revealing finding of very low safety significance concerning the licensee's failure to identify a deficient condition due to preconditioned speed testing of station switchyard breakers and properly evaluate three similar failures of station switchyard breakers. As a result, three switchyard breakers opened slowly on August 15, 2004, and a transmission line ground fault that should have been isolated from the station switchyard remained connected to the main transformer long enough to cause a main generator lockout and reactor scram. Additionally, because slow breaker opening deenergized the north 230 kV bus, isolation of a coincident transmission line fault resulted in a loss of power to half of the balance of plant loads and the Division II engineered safety features switchboard.

  This problem identification and resolution finding was more than minor because it was associated with the initiating events cornerstone objective to limit those events that upset plant stability and challenge a critical safety function during power operations. The inspectors evaluated the finding using Instruction Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." Because the finding contributed to the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available, the finding required a Phase 2 analysis. The inspectors referred the results of the Phase 2 analysis to the regional senior reactor analyst for final determination of risk.

  The senior reactor analyst performed a Phase 3 analysis of the event. The factors that contributed to the result of that analysis included: (1) the dominant sequence was a transient with a loss of power to a vital bus; (2) the consequences of the finding were bounded by a complete loss of offsite power; (3) the history of single slow switchyard breaker operation; (4) the design and layout of the station switchyard; and (4) the possibility of recovery from either a partial or complete loss of offsite power given the conditions that led to the events of August 15, 2004. The result was that the finding was of very low safety significance (Section 4OA5).

Cornerstone: Mitigating Systems

- Green. A self-revealing, noncited violation of 10 CFR 55.46(c) was identified regarding differences between the simulator's and the plant's wide-range reactor water level digital indications during an unplanned reactor scram. This unexpected level indication resulted in indecision on the part of the operators during postscram recovery actions on December 10, 2004.

  This finding is more than minor since deficiencies in the operator training program could become a more significant safety concern if left uncorrected. Based on the results of the significance determination process using Inspection Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process," this finding was determined to have very low safety significance, since it did not involve an exam or operating test but did involve a simulator fidelity issue which impacted operator actions during the response to an actual transient in the plant (Section 1R14).

- Green. The inspectors identified a self-revealing noncited violation of 10 CFR Part 50 Appendix B, Criterion XVI, for the licensee's failure to take timely and effective corrective action to prevent recurrence of rainwater leakage from the auxiliary building roof onto auxiliary building 480 Vac safety-related Switchgear EJS-SWGR2A, causing a loss of auxiliary building area unit Cooler HVR-UC11A. Investigation into the source of water determined that rainwater was accumulating inside the auxiliary building fresh air intake structure on the roof and leaking through seals along the air inlet ductwork onto Switchgear EJS-SWGR2A. The inspectors determined that this was a repeat of a February 5, 2004, leak documented in River Bend Station Condition Report 2004-0346 and a problem identification and resolution Noncited Violation 05000458/2004002-02. This finding had crosscutting aspects related to ineffective corrective actions.

  The inspectors determined that the licensee's failure to take timely and effective corrective action to stop rainwater leaks from the auxiliary building roof onto Switchgear EJS-SWG2A was a performance deficiency that caused the loss of Cooler HVR-UC11A. The finding was more than minor because, if left uncorrected, rainwater leaks from the auxiliary building roof could lead to the loss of other Division I safety-related equipment and motor control centers powered by Switchgear EJS-SWG2A. The inspectors reviewed the finding using Inspection Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." Based on the results of the Phase 1 screening of the finding, the inspectors determined that the finding was of very low safety significance because the short-term loss of unit Cooler HVR-UC11A did not cause an actual loss of safety function of any train of Technical Specification risk significant equipment and was not potentially risk significant due to a seismic, flooding, or severe weather initiating event. The inspectors determined that the failure to take timely and effective actions to prevent rainwater from leaking onto Switchgear EJS-SWGR2A was a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action." Because this finding was of very low safety significance and was entered into the licensee's corrective action program as

CR-RBS-2004-4218, this violation is being treated as a noncited violation, consistent with Section IV.A of the NRC Enforcement Policy, NUREG-1600 (Section 4OA2).

Cornerstone: Barrier Integrity

- Green. The inspector identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion IX, for failure to control special processes, such as welding, in accordance with qualified welding procedures as required. The finding was a human performance error for the failure to follow procedure. Criterion IX, Appendix B, of 10 CFR Part 50, "Control of Special Processes," requires in part that measures shall be established to assure that special processes, including welding, heat treating, and nondestructive testing are controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, specifications, criteria, and other special requirements. Contrary to the above, welding personnel failed to verify interpass temperature during welding activities on feedwater inlet check Valve B21-AOVF032, an ASME Class1 valve, in accordance with qualified welding procedures.

  This finding was determined to be more than minor, through Inspection Manual Chapter 0612, Appendix B, in that it affected the barrier integrity cornerstone attribute of human performance, could have represented a more significant issue if left uncorrected, and there was a reasonable likelihood that the valve would have been returned to service if the inspector had not intervened. Based on the results of a significance determination process Phase 1 analysis, this finding had very low safety significance because it did not result in the loss of a barrier integrity function and has been entered into the licensee's corrective action program as Condition Report CR-RBS-2004-03395. This violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy, NUREG-1600 (Section 1R08).

Cornerstone: Occupational Radiation Safety

- Green. The inspector reviewed a self-revealing noncited violation of Technical Specification 5.7.3 because the licensee failed to control a high radiation area with dose rates greater than 1,000 millirems per hour. On October 31, 2004, during maintenance activities on valves located on the 82-foot level of the drywell, three workers' electronic alarming dosimeters unexpectedly alarmed when they were exposed to unanticipated radiation levels of approximately 1,700 millirems per hour. Subsequent radiation surveys at the source of radiation around Valve RCS-V-3009 identified 6,000 millirems per hour on contact and 2,000 millirems per hour at 30 centimeters. The area was not barricaded, conspicuously posted, and did not have a flashing light activated as a warning device. The licensee determined that the three workers received 84, 85, and 95 millirems, respectively. This finding was entered into the licensee's corrective action program.

  This finding is more than minor because it is associated with the Occupational Radiation Safety attribute of exposure control and affected the cornerstone objective, in that not controlling locked high radiation areas could increase personal exposure. Using the

Occupational Radiation Safety Significance Determination Process, the inspector determined that the finding was of very low safety significance (Green) because it did not involve: (1) as low as is reasonably achievable planning and controls, (2) an overexposure, (3) a substantial potential for overexposure, or (4) an impaired ability to assess dose (Section 2OS1).

B. Licensee-Identified Violations

Two violations of very low safety significance, which were identified by the licensee, have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status: On October 1, 2004, the reactor shut down automatically due to an insulator arc-over on the main transformer, causing a generator lockout and reactor scram. The reactor was restarted on October 6, 2004, and attained 100 percent power on October 10, 2004. The reactor was shut down for refueling on October 21, 2004. The plant remained in cold shutdown until restarted on November 18, 2004; 100 percent power was attained on November 25, 2004. On December 10, 2004, the reactor automatically shut down due to a failure of an instrumentation inverter. The reactor was restarted on December 12, 2004, and attained 100 percent power on December 14, 2004. The plant was operated at 100 percent power for the remainder of the inspection report period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

.1 Cold Weather Preparation

During the week of December 1, 2004, the inspectors reviewed the licensee's plant procedures used to protect mitigating systems from freezing weather conditions. Specifically, the inspectors: (1) verified that temperature had been frequently monitored; (2) verified that operation of plant features during freezing conditions were appropriate; and (3) evaluated implementation of the freezing weather preparation procedures and compensatory measures for affected systems or components before the onset of freezing weather conditions. The inspectors reviewed Operations Section Procedure OSP-0043, "Freeze Protection and Temperature Maintenance," Revisions 4 and 5, including the attachments completed for cold weather conditions during November and December 2004.

.2 Severe Thunderstorm Warning

On November 24, 2004, the inspectors observed and evaluated implementation of severe weather preparation procedures and compensatory measures for a national weather service severe thunderstorm warning for the plant vicinity. Specifically, the inspectors verified that actions taken were in accordance with the station's adverse weather preparations procedures and maintained availability of essential systems and components, including postponement of surveillance testing of safety-related systems. Additionally, the inspectors walked down outside portions of the plant to ensure that essential plant equipment would not be affected by high winds and flying debris. The inspectors reviewed the control room record copy of Procedure AOP-0029, "Severe Weather Operation," Revision 14B.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors performed three partial system walkdowns during this inspection period. On November 2, 2004, the inspectors walked down residual heat removal (RHR) Train A after it was placed in fuel pool cooling assist mode following a loss of offsite power. On December 1, 2004, the inspectors walked down reactor core isolation cooling (RCIC) while the high pressure core spray (HPCS) on-site electrical supply emergency diesel generator was out of service for preplanned surveillance testing. On December 6, 2004, the inspectors walked down the Division II standby service water system while the Division I standby service water system was inoperable due to an electrical ground on Division I switchgear. In each case, the inspectors verified the correct valve and power alignments by comparing positions of valves, switches, and electrical power breakers to the system operating procedures (SOP) and applicable sections of the Updated Safety Analysis Report (USAR). The following procedures were reviewed:

- SOP-0031, “Residual Heat Removal System,” Revision 43
- SOP-0035, “Reactor Core Isolation Cooling System,” Revision 23
- SOP-0041, “Standby Service Water System,” Revision 11

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors walked down accessible portions of eight areas described below to assess: (1) the licensee’s control of transient combustible material and ignition sources; (2) fire detection and suppression capabilities; (3) manual firefighting equipment and capability; (4) the condition of passive fire protection features, such as, electrical raceway fire barrier systems, fire doors, and fire barrier penetrations; and (5) any related compensatory measures. The areas inspected were:

- Auxiliary building, 95-foot elevation, low pressure core spray system panel room, Fire Area AB-6/Z-2, on November 19, 2004

- Auxiliary building, 95-foot elevation, shield building access area, Fire Area AB-15/Z-2, on November 19, 2004

- Auxiliary building, 95-foot elevation, high pressure core spray system piping area, Fire Area AB-2/Z-2, on November 19, 2004

- Auxiliary building, 141-foot elevation, standby gas treatment Filter A room, Fire Zone AB-14, on November 19, 2004

- Auxiliary building, 141-foot elevation, standby gas treatment Filter B room, Fire Area AB-13, on November 19, 2004

- Fire protection water pump house, electric- and diesel-driven fire pump rooms, Fire Area FP-1, FP-2 and FP-3, on December 1, 2004

- Fire protection water pump house, domestic water pump room, Fire Area FP-4, on December 1, 2004

- Control building, 98-foot elevation, cable Chase IV, which houses safety-related electrical cables, on December 6, 2004.

The inspectors reviewed the following documents during the fire protection inspections:

- Pre-Fire Plan/Strategy Book
- USAR Appendix 9A.2, “Fire Hazards Analysis,” Revision 15
- River Bend Station postfire safe shutdown analysis
- RBNP-038, “Site Fire Protection Program,” Revision 9A

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors conducted a periodic external flooding assessment to verify that the licensee’s flood mitigation plans and equipment were consistent with design requirements and risk analysis assumptions. Specifically, the inspectors examined: (1) design sources, volume flow rates, and flow paths of high energy and moderate energy line cracks; (2) design flood levels and conditions; (3) the ability of the walls to withstand the hydrodynamic forces associated with the design flood levels; (4) flood protection requirements; (5) assumptions in the design analysis to verify they were met in actual practice; and (6) alarm response and emergency procedures for coping with flooding to verify that they could reasonably be used to achieve the desired actions, including whether the flooding event could limit or preclude the required operator actions. The inspectors walked down postulated flowpaths of flooding in the auxiliary building from higher elevations down into emergency core cooling system (ECCS) pump rooms. The inspectors also reviewed the documents listed in the attachment to this inspection report and interviewed station personnel.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

.1 Performance of Testing, Maintenance, and Inspection Activities

a. Inspection Scope

Inspection Procedure 71111.07B requires selecting two to three risk-significant heat exchangers that are directly or indirectly connected to the safety-related service water system for review. The inspector reviewed the following three samples during this inspection: RHR heat exchanger, containment coolers, and RCIC pump room coolers. The inspector reviewed the licensee's test and cleaning methodology for the RHR heat exchanger, containment coolers, and RCIC pump room coolers. In addition, the inspector reviewed test data for the RHR heat exchangers and design and vendor-supplied information to ensure that the heat exchangers were performing within their design bases. The inspector also reviewed the heat exchanger inspection and test results. Specifically, the inspector verified: (1) proper extrapolation of test conditions to design conditions, (2) appropriate use of test instrumentation, and (3) appropriate accounting for instrument inaccuracies. Additionally, the inspector verified that the licensee appropriately trended these inspection and test results, assessed the causes of the trends, and took necessary actions for any step changes in these trends. The inspector reviewed the methods and results of heat exchanger inspection and cleaning and verified that the methods used to inspect and clean were consistent with industry standards. The inspector also verified that as-found results were appropriately dispositioned such that the final conditions were acceptable. The inspector reviewed the documents listed in the attachment to this report as part of this inspection.

b. Findings

No findings of significance were identified.

.2 Verification of Conditions and Operations Consistent with Design Bases

a. Inspection Scope

For the selected heat exchangers, the inspector verified that the heat sink and heat exchanger condition, operation, and test criteria were consistent with the design assumptions. Specifically, the inspector reviewed the applicable calculations to ensure that the thermal performance test acceptance criteria for the heat exchangers were being applied consistently throughout the calculations. The inspector also verified that the appropriate acceptance values for fouling and tube plugging for the RHR heat exchangers remained consistent with the values used in the design-bases calculations. Finally, the inspector verified that the parameters measured during the thermal performance tests for the RHR heat exchangers were consistent with those assumed in the design bases. The inspector reviewed the documents listed in the attachment to this report as part of this inspection.

b. Findings

No findings of significance were identified.

.3 Identification and Resolution of Problems

a. Inspection Scope

The inspector verified that the licensee had entered significant heat exchanger/heat sink performance problems into the corrective action program. The inspectors reviewed 15 condition reports (CRs), which are listed in the attachment to this report as part of this inspection.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

1. Performance of Nondestructive Examination (NDE) Activities for Boiling Water Reactors (BWR)

a. Inspection Scope

The procedure requires a sample review of two or three types of NDE activities, which include: (a) volumetric examinations, (b) surface examinations, and (c) visual examinations. This was completed in the review of volumetric and surface examinations. For each NDE activity reviewed, perform the following through either direct observation (preferred method) or record review. The inspector reviewed the records of six American Society of Mechanical Engineers (ASME) Section XI volumetric examinations, reviewed records and witnessed the performance of six BWR vessel and internals project (BWRVIP) inspections, and witnessed the performance of one ASME repair/replacement welding activity. The sample of NDE activities reviewed is listed in the attachment.

For each of the NDE activities reviewed, the inspector verified that the examinations were performed in accordance with site procedures and the applicable ASME code requirements.

During the review of each examination, the inspector verified that appropriate NDE procedures were used, that examinations and conditions were as specified in the procedure, and that test instrumentation or equipment was properly calibrated and within the allowable calibration period. The inspector also reviewed documentation to verify that indications revealed by the examinations were dispositioned in accordance with site procedures and the ASME code specified acceptance standards.

The inspector verified the certifications of eight General Electric, six Tecnatom, three Washington Group, and four Areva NDE personnel observed performing examinations or identified during review of completed examination packages.

The inspection procedure requires review of one or two examinations from the previous outage with recordable indications that were accepted for continued service to ensure that the disposition was done in accordance with the ASME code. There were no recordable indications accepted for continued service.

If welding on the pressure boundary for Class 1 or 2 systems has been completed by the licensee, the procedure requires verification for one to three welds that the welding process and welding examinations were performed in accordance with the ASME code. The inspectors witnessed one ASME Class 1 activity in progress pertaining to the replacement and welding of a new seat for feedwater inlet check Valve B21-AOVF032 located in the steam tunnel. Welding on this valve seat was performed using Work Order (WO) 50357393.

b. Findings

Introduction. A Green noncited violation (NCV) was identified for failure to control special processes, such as welding, in accordance with qualified welding procedures as required.

Description. On October 28, 2004, the inspector was observing welding activities on feedwater inlet check Valve B21-AOVF032 located in the steam tunnel. Welders were welding in a new seat for this ASME Class 1 valve. The welders were contract welders using an automatic welding process. During this activity, the inspector questioned the welder on procedural requirements, welding processes used, various parameters involved, such as voltage/amperage of the welding machine, and preheat and interpass temperature. When questioned about verifying interpass temperature, the welder informed the inspector that he had not verified the interpass temperature. He stated that based on experience the interpass temperature had not exceeded 500EF.

Upon leaving the steam tunnel, the inspector requested the welding requirements for the welding activity witnessed from licensee quality control personnel. Further review by the inspector indicated that welding procedure Specification E-P1-T(M)-A8-CRO-HO requires verification of preheat and interpass temperature using a temperature indicating crayon or a thermocouple pyrometer. Also, review of the weld data sheet for this welding activity indicated a maximum interpass temperature of 250EF and not 500EF as originally stated by the welder.

The inspector informed the licensee of this finding, and the licensee immediately took action. A stand down with all welding personnel was conducted to reinforce expectations for procedural compliance, specifically for the contract welders. The licensee initiated CR-RBS-2004-03395 to address this issue and document proposed corrective actions. Prior to the exit meeting, the licensee informed the inspector that an evaluation would be performed to determine the weld quality.

Analysis. The inspector identified a performance deficiency for the failure to control special processes such as welding in accordance with qualified welding procedures as required. This finding was determined to be more than minor, through Inspection Manual Chapter (IMC) 0612, Appendix B, in that it affected the barrier cornerstone attribute of human performance, it could have represented a more significant issue if left uncorrected, and there was a reasonable likelihood that the valve would have been returned to service if the inspector had not intervened. A significance determination process Phase 1 screening was performed and the finding was determined to have very low safety significance (Green) because there was no actual loss of the barrier integrity function. The licensee entered this finding into their corrective action program as CR-RBS-2004-03395. The finding involved human performance error regarding failure to follow procedural requirements.

Enforcement. Criterion IX of 10 CFR Part 50, Appendix B, "Control of Special Processes," requires in part that measures shall be established to assure that special processes, including welding, heat treating, and NDE testing are controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, specifications, criteria, and other special requirements. Contrary to the above, welding personnel failed to verify interpass temperature during welding activities on the feedwater inlet check Valve B21-AOVF032 seat in accordance with qualified welding procedures as required. Because the finding is of very low safety significance (Green) and has been entered into the licensee’s corrective action program as CR-RBS-2004-03395, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy, NUREG-1600 (NCV 05000458/2004005-01).

.2 Identification and Resolution of Problems

a. Inspection Scope

The inspector reviewed 17 selected inservice inspection related conditions reports issued during the current and past refueling outages. The review served to verify that the licensee’s corrective action process was being correctly utilized to identify conditions adverse to quality and that those conditions were being adequately evaluated, corrected, and trended. The inspector determined that the licensee’s threshold for initiating CRs was low, thereby, capturing most deficiencies identified in the inservice inspection program.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

c. Inspection Scope

On November 12, 2004, the inspectors observed simulator training of an operating crew as part of just-in-time operator requalification training in preparation for the plant startup following Refueling Outage 12 (RFO-12). The inspectors assessed licensed operator performance and the training evaluator's critique. Emphasis was placed on observing exercises with high risk licensed operator actions, operator actions associated with approach to criticality, establishing a heatup rate, rolling the main turbine, and lessons learned from industry and plant experiences. In addition, the inspectors compared simulator control panel configurations with the actual control room panels for consistency, including recent modifications implemented in the plant. The following documents were reviewed as part of the inspection:

- Simulator Instructor Guide, RSTG-LOR-JIT0033, "Simulator Instructor Guide for Startup/Shutdown," Revision 4
- Simulator Scenario, RSMS-OPS-312, "Reactor Startup," Revision 0
- Simulator Scenario, RSMS-OPS-307, "Turbine Startup with Nuclear Instrumentation Miscalibration," Revision 1

b. Findings

No findings of significance were identified.

1R12 Maintenance Implementation (71111.12)

a. Inspection Scope

The inspectors reviewed two instrument air system (IAS) performance problems associated with the diesel-driven air Compressor IAS-C4 to assess the effectiveness of the licensee's maintenance efforts for structures, systems, or components (SSC) within the scope of the maintenance rule program. The licensee has classified IAS as (a)1 because of problems with IAS-C4. The inspectors verified the licensee's maintenance effectiveness by: (1) verifying the licensee's handling of SSC performance or condition problems, (2) verifying the licensee's handling of degraded SSC functional performance or condition, (3) evaluating the role of work practices and common cause problems, and (4) evaluating the licensee's handling of the SSC issues being reviewed under the requirements of the maintenance rule (10 CFR 50.65), 10 CFR Part 50, Appendix B, and the Technical Specifications.

- CR-RBS-2003-3083, diesel-driven air compressor dryer in line lubricator is empty, reviewed on December 20, 2004

- CR-RBS-2004-1996, after startup of diesel-driven air compressor for weekly run, an engine coolant leak was found, reviewed on December 20, 2004

The following documents were reviewed as part of this inspection:

- NUMARC 93-01, Nuclear Energy Institute (NEI) Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 2
- Maintenance rule function list
- Maintenance rule performance criteria list
- IAS maintenance rule performance evaluations

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation (71111.13)

a. Inspection Scope

The inspectors reviewed four maintenance activities to verify the performance of assessments of plant risk related to planned and emergent maintenance work activities. The inspectors verified: (1) the adequacy of the risk assessments and the accuracy and completeness of the information considered, (2) management of the resultant risk and implementation of work controls and risk management actions, and (3) effective control of emergent work, including prompt reassessment of resultant plant risk.

During emergent work, the inspectors verified that the licensee took actions to minimize the probability of initiating events and maintained the functional capability of mitigating systems. The inspectors also reviewed the emergent work activities to ensure the plant was not placed in an unacceptable configuration. The four emergent work activities evaluated were:

- Service water cooling system supply Transformer STX-XS5A out of service from July 21 to September 28, 2004
- Offsite power to protected Division II electrical distribution system out of service on November 1, 2004
- Diesel-driven fire Pump FPW-P1A, out of service during the week of November 29, 2004
- Division II safety-related battery Charger 1ENB-CHGR1B out of service on December 2, 2004

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions (71111.14)

.1 Reactor Scram with Partial Loss of Offsite Power

a. Inspection Scope

On October 1, 2004, the inspectors observed the operators' response to a loss of reserve station service Transformer 1 (RSS 1). The inspectors observed initial response to the loss of the Division I engineered safety features (ESF) electrical switchgear, including the restoration of the reactor protection system power supply and instrument air and closed cooling water to primary containment.

Twelve minutes later a main transformer ground fault and main generator lockout occurred. The reactor scrammed on turbine control valve fast closure and main feedwater was lost due to the preexisting problem with RSS 1. The operators responded by controlling level with HPCS. Following a loss of condenser vacuum, the operators controlled reactor pressure using safety relief valves, which necessitated the use of RHR for suppression pool cooling. The inspectors noted that the loss of condenser vacuum was hastened by the failure of the operators to properly operate the main circulating water system.

The initiating event was the shorting to ground of high voltage insulators on the incoming line to RSS 1 and the outgoing line from the main transformer. The inspectors reviewed the abnormal operating procedures and emergency operating procedures used by the operators during the evolution. They are listed in the attachment.

b. Findings

This event and the operators' response was the subject of a special inspection and was documented in NRC Inspection Report 05000458/2004012.

.2 Loss of Offsite Power to Protected Division ECCS

a. Inspection Scope

The inspectors reviewed personnel performance during a November 1, 2004, loss of one offsite power source, RSS 2, that caused a loss of shutdown cooling, loss of alternate decay heat removal, automatic containment isolations, and automatic start of Division II emergency diesel generator by direct observation of control room team response and by interviewing control room team members. In addition, the inspectors reviewed operator logs and plant computer data to determine what had occurred and whether the operators responded in accordance with plant procedures and training.

Also, see Section 1R20. The inspectors reviewed the following procedures and computer program used by the operators during the event:

- AOP-0051, "Loss of Decay Heat Removal," Revision 17
- AOP-0003, "Automatic Isolations," Revision 21
- OSP-0037, "Shutdown Operations Protection Plan," Revision 14
- OSP-0041, "Alternate Decay Heat Removal," Revision 8
- Equipment Out of Service computer program, November 1, 2004

g. Findings

No findings of significance were identified.

.3 Loss of Nonsafety-Related Instrument Bus Results in a Complicated Reactor Scram

a. Inspection Scope

On December 10, 2004, the inspectors observed operator response to a loss of nonsafety-related instrumentation Bus VBN-PNL01B1 and the resultant reactor scram. The reactor scrammed on high average power range monitor (APRM) power. The operators responded by controlling reactor water level with HPCS and reactor pressure using the main turbine bypass valves and main steam line drains.

The initiating event was a failed capacitor on the static switch control board for nonsafety-related static Inverter BYS-INV01B. The inspectors reviewed the procedures used by the operators during the evolution. They are listed in the attachment.

b. Findings

Introduction. The inspectors identified a self-revealing NCV of 10 CFR 55.46(c) because differences between the simulator's and the plant's wide-range reactor water level recorders' digital indications resulted in indecision on the part of the operators during postscram recovery actions following a loss of a nonsafety-related instrumentation bus.

Description. On December 10, 2004, a capacitor shorted on the static switch control board for nonsafety-related static Inverter BYS-INV01B, and power was lost to instrumentation Bus VBN-PNL01B1. This resulted in a loss of control power to the feedwater regulating valves. As a result, the valves locked up in the 100 percent flow position. Reactor recirculation Pump B also downshifted to slow speed due to a loss of control power. This resulted in an overfeed condition and the additional cold water caused an increase in thermal neutron power. The lowering recirculation system flow caused the APRM power-to-flow scram setpoint to lower. The reactor scrammed on high APRM power.

Following the reactor scram, with the feedwater regulating valves in the 100 percent flow position, reactor water level rose to the high level trip setpoint and the reactor feed pumps tripped. In response, the operators initiated RCIC to maintain reactor water level, which should have lowered rapidly had the feedwater regulating valves not been locked up in the 100 percent flow position. Immediately after RCIC was initiated, it shut down in response to the high reactor water level trip signal. The operators then prepared to reinitiate RCIC once the high reactor water level trip cleared as the reactor continued to generate steam through the main turbine bypass valves to the main condenser.

However, wide-range reactor water level Recorders B21-R623A and -B digital indications continued to rise above the top of scale, +60 inches. The indication stopped rising at +150 inches. The operators questioned the further use of RCIC for water level control, concerned that the main steam lines may be filled with water. The main steam lines leave the reactor at approximately +95 inches. The operators discussed an operating experience event during which operators at another plant started RCIC with water in its steam supply line. In that instance, the turbine tripped on overspeed and required local operation to reset the turbine trip. Also, complicating the operators' decision making process was the loss of the only valid indication of reactor water level (the upset range, which was lost due to the loss of Bus VBN-PNL10B1) and unexpected RCIC alarms.

As a result, when level returned on-scale on the wide-range and narrow-range reactor water level instruments, the operators used HPCS for reactor water level control. This complicated the operators' response to the event, since HPCS adds water to the suppression pool when it is not being used to add water to the reactor. As a result, the operators had to start the RHR system in suppression pool cooling to facilitate rejecting water from the suppression pool to radwaste to maintain suppression pool level below high level action points.

Following the event, the inspectors interviewed the operators, who all stated that they had never seen wide-range level indication above +60 inches. They all stated that they had trained on reactor overfill events in the simulator and that the simulator's B21-R623A and -B recorders' digital indication stopped at +60 inches. They would then use other indications, such as steam line drain trap alarms and upset range reactor water level, to determine whether the steam lines were flooded.

The inspectors interviewed a reactor instrumentation system engineer and reviewed the modification paperwork that installed the current digital wide-range level recorders. The engineer stated that the wide-range level transmitters will go into saturation when level rises above the reference leg tap for the instrument at +65 inches. As a result, the transmitter will send an overrange signal to the recorder and the digital indication will read greater than +60 inches. The inspectors then interviewed the engineer who maintains the training simulator. He stated that the simulator's wide-range level recorder digital indications stop reading at +60 inches, because the instrumentation loop calibration report for the recorders only covers the valid range of the wide-range level instruments, -160 to +60 inches.

The inspectors determined that the training given in the simulator for reactor overfill events and the maximum simulator's wide-range level indication of +60 inches had a definite impact on the operators' decision making process on December 20, 2004. Because of the higher than expected wide-range digital indication, the operators did not use RCIC for reactor water level control. This complicated their response to the scram and caused them to use HPCS which added water to the suppression pool and required running RHR to control suppression pool level.

Analysis. This finding involved a licensed operator training deficiency regarding wide-range reactor water level indication response to a reactor overfill event. Therefore, this finding affected the mitigating systems cornerstone since it impacted the operators' response to mitigate the consequences of this transient and was considered more than minor since deficiencies in the operator training program could become a more significant safety concern if left uncorrected. Based on the results of the significance determination process using IMC 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process," this finding was determined to have very low safety significance (Green), since it did not involve an exam or operating test but did involve a simulator fidelity issue which impacted operator actions during the response to an actual transient in the plant.

Enforcement. 10 CFR 55.46(c) requires that plant referenced simulators used for operating tests or to meet experience requirements must demonstrate expected plant response to transient conditions to which the simulator was designed to respond. The River Bend Station simulator was designed to respond to reactor overfill events; however, the simulator response differed from actual plant response in that wide-range reactor water level digital indication does not indicate greater than +60 inches when level goes above the +65 inches, the reference leg tap for the wide-range level transmitter. The failure to adequately model plant response in the simulator, discovered on December 20, 2004, is a violation of 10 CFR 55.46(c). Because this violation was of very low safety significance (Green) and was entered into the licensee's corrective action program as CR-RBS-2004-4296, it is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy, NUREG-1600 (NCV 50-459/2004005-02).

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

During the inspection period, the inspectors reviewed three operability determinations selected on the basis of risk insights. The selected samples are addressed in the CRs listed below. The inspectors assessed: (1) the accuracy of the evaluations; (2) the use and control of compensatory measures, if needed; and (3) compliance with Technical Specifications, the Technical Requirements Manual, the USAR, and other associated design-basis documents. The inspectors' review included a verification that the operability determinations were made as specified by Procedure RBNP-078, "Operability Determinations," Revision 7. The operability evaluations reviewed were associated with:

- CR-RBS-2004-2853, Received multiple half scrams during postscram recovery on October 1 due to high reactor water Level 8 with mode switch in shutdown, reviewed on October 7, 2004

- Calculation 228.800-PX-562, “Waltham Analysis with Trapped Air in Standby Service Water System Header and Loss of Normal Service Water/Loss of Reactor Plant Closed Cooling & Loss of Offsite Power Events,” Revision 2, reviewed on December 6, 2004

- CR-RBS-2004-4203, Division II battery charger operable but degraded, reviewed December 9-10, 2004

e. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

An operator workaround is defined as a degraded or nonconforming condition that complicates the operation of plant equipment and is compensated for by operator action. During the week of October 16, 2004, the inspectors reviewed the cumulative effect of the existing operator workarounds and contingency plans that existed prior to RFO-12. During the week of December 6, 2004, the inspectors reviewed the cumulative effect of the existing operator workarounds and contingency plans in effect after the refueling outage. The inspectors concentrated on the effect the workarounds have on: (1) the reliability, availability, and potential for misoperation of any mitigating system; (2) whether they could increase the frequency of an initiating event; and (3) their effect on the operation of multiple mitigating systems. In addition, the inspectors reviewed the cumulative effects the operator workarounds have on the ability of the operators to respond in a correct and timely manner to plant transients and accidents. The procedures and other documents reviewed by the inspectors during this inspection are listed in the attachment to this report.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed four postmaintenance testing activities to ensure that postmaintenance testing was adequate to verify system operability and functional capability. The inspectors: (1) identified the safety function(s) for each system by reviewing applicable licensing basis and/or design-basis documents; (2) reviewed each maintenance activity to identify which maintenance function(s) may have been affected; (3) reviewed each test procedure to verify that the procedure did adequately test the safety function(s) that may have been affected by the maintenance activity; (4) ensured that the acceptance criteria in the procedure were consistent with information in the applicable licensing basis and/or design-basis documents; and (5) identified that the procedure was properly reviewed and approved. The inspectors completed this inspection by reviewing completed WOs and station drawings listed in the attachment to this inspection report and by interviewing station personnel. The four postmaintenance tests reviewed were:

- WO 50087, Troubleshoot reactor mode switch for Channel C Level 8 half scram with mode switch in shutdown, reviewed on October 12, 2004
- E12-MOVF008 leak rate as-left test, conducted on November 7, 2004
- E12-MOVF008 pressure isolation test, conducted on November 8, 2004
- E12-MOVF008 stroke time test, conducted on November 14, 2004

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope

The inspectors reviewed the shutdown outage protection plan for RFO-12, conducted October 21 through November 17, 2004, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan for RFO-12. The documents reviewed as part of this inspection are listed in the attachment. During the refueling outage, the inspectors observed and reviewed the outage activities listed below:

- Reactor shutdown, specifically: downshift of reactor recirculation pumps to slow speed, reactor scram, plant cooldown, and transition to shutdown cooling
- Initial drywell entry and inspection
- Outage control center meetings, especially 7 a.m. turnover and status meetings
- Preparations for Division II loss of offsite power and loss of coolant testing
- Reactor fuel and control rod movement and reactor core verification
- Troubleshooting problems with inclined fuel transfer system

- Reactor vessel nozzle inservice inspection examinations
- Protected division swap and start of RHR System B in shutdown cooling
- Local leak testing of containment isolation valves, such as main steam isolation valves
- Motor-operated valve signature testing, such as shutdown cooling outboard containment isolation valve
- Inservice testing of plant components, such as RHR containment isolation valves
- Troubleshooting the main turbine mechanical trip system
- Onsite safety review committee meeting which recommended startup, including review of outstanding Generic Letter 91-18, “Operable but Degraded,” issues
- Preparations for reactor startup, including drywell closeout inspection
- Reactor startup, including approach to criticality and plant heatup

In addition, the inspectors observed response to and reviewed corrective actions taken in response to human performance errors which resulted in unexpected losses of or damage to plant equipment during the refueling outage, including, but not limited to:

- Inclined fuel transfer system bottom valve failure
- Refuel platform frame mounted hoist caught on reactor cavity railing
- Unexpected start of auxiliary building unit Cooler HVR-UC11B during tagout restoration
- Unexpected start of Division II emergency diesel generator during tagout restoration
- Loss of Division I ESF 4160 Vac bus and start of Division I emergency diesel generator (See Section 4OA2.)
- Loss of RSS 2 and loss of shutdown cooling

b. Findings

Loss of Offsite Power to Protected Division and Shutdown Cooling

Introduction. The inspectors reviewed a self-revealing NCV of very low safety significance (Green) for the licensee’s failure to revise a tagging boundary to support an emergent troubleshooting task. This performance deficiency resulted in the loss of offsite power to Division II safety-related equipment, loss of shutdown cooling, loss of alternate decay heat removal, containment isolations, and an automatic start of the Division II emergency diesel generator.

Description. On October 30, 2004, the licensee cleared Tagout 311-RSS-2-001 to energize Division II ESF offsite power supply Transformer RTX-XSRID and allow for a protected division swap to permit testing and maintenance of Division I ESF equipment. At the same time, the licensee hung Tagout 311-RTX-XSR1F-012-E to allow completion of planned maintenance on the Division II balance of plant offsite power supply Transformer RTX-XSR1F.

On November 1, 2004, a routine task for testing the sudden pressure protection circuitry for Transformer RTX-XSR1F was performed. Because the trip relay did not pass the required test, work was stopped, the system was returned to normal, and a troubleshooting plan was developed to correct the problem. The technicians discussed the troubleshooting plan with the responsible system engineer but did not present the new work package to work control for review of the operational impact of this emergent work. As a result, operations personnel did not revise the existing Tagout 311-RTX-XSR1F-012-E to isolate the sudden pressure relay from the transformer protection circuit. Following testing of the two sudden pressure sensors, one was returned to the relay trip circuit before the sensor was reset. Because the sudden pressure relay was not isolated from the transformer protection circuit by the tagging boundary, and the tagout was not revised to isolate the transformer trip circuit, the tagout did not confine the troubleshooting task nor protect equipment outside of the boundary during the troubleshooting.

As a result, a trip signal from the Transformer RTX-XSR1F sudden overpressure relay opened 230 Kv switchyard Breakers OCB-20670 and OCB-20665. The trip of these breakers de-energized RSS-2, which de-energized Division II ESF offsite power supply Transformer RTX-XSRID and Division II ESF equipment.

De-energizing the Division II ESF equipment caused: (1) a loss of shutdown cooling (RHR Pump B), (2) an automatic isolation of reactor water cleanup, alternate decay heat removal, and containment floor and equipment drain lines, and (3) an automatic start of the Division II emergency diesel generator.

Following the loss of offsite power to Division II ESF equipment, the licensee halted refueling operations. The licensee restored RHR Pump B (powered by the Division II emergency diesel generator) to fuel pool cooling assist mode on the upper pools for shutdown cooling within an hour. The calculated time for the reactor coolant system (RCS) to reach 200EF was greater than 12 hours. RHR Pump A was available throughout the event to supply shutdown cooling and could have been powered by either offsite power or the Division I emergency diesel generator.

On November 2, 2004, following recovery from the event, Tagout 311-RTX-XSR1F-012-E was modified to isolate the sudden overpressure relay for

Transformer RTX-XSR1F so that troubleshooting could resume. Division II safety-related equipment was re-energized by RSS 2, and the Division II emergency diesel generator was shut down.

The licensee determined that other administrative controls could have prevented the loss of offsite power to Division II ESF switchgear. For instance, the troubleshooting plan could have provided directions to lift the sudden pressure trip relay leads. The licensee also determined that communications between the responsible system engineer and the technicians did not describe the condition of the sudden pressure trip relay and the potential impact of not resetting the sudden pressure sensors.

Analysis. The inspectors determined that this self-revealing finding was more than minor because it was associated with the initiating events cornerstone attributes to protect against external factors, including switchyard activities, and because the finding affected the associated cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations.

The inspectors analyzed the finding using IMC 0609, Appendix G, “Shutdown Operations Significance Determination Process.” The inspectors determined that the Attachment 1, Checklist 7, “BWR Refueling Operations with RCS Level greater than 23',” Item I.C, “Core Heat Removal Guidelines/Equipment,” requirement of having at least one RHR loop operable and in operation with necessary support systems was not met.

The inspectors reviewed the section of Attachment 1, Checklist 7, labeled, “Findings requiring Phase 2 analysis,” and determined there was no need for this finding to be quantitatively assessed with a Phase 2 or 3 significance determination process because there was no increased likelihood of a loss of RCS inventory, there was no loss of RCS level instrumentation, there was no degradation of the licensee’s ability to terminate a leak path or add RCS inventory when needed, nor any degradation of the licensee’s ability to recover decay heat removal once it was lost. Therefore, this finding screened as having very low risk significance (Green).

This finding had crosscutting aspects regarding human performance (organization) in that a lack of coordination and review following a change in work scope resulted in the observed event.

Enforcement. Technical Specification 5.4.1.a requires that procedures be established, implemented, and maintained as recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Regulatory Guide 1.33, Appendix A, Section 1.c, lists procedures for implementation of an equipment control (e.g., locking and tagging) program. Procedure OSP-0038, “Protective Tagging Guidelines,” Revision 15, Section 3.6.3, stated “An isolation boundary will be established to confine the testing activity and to protect equipment and personnel outside of the boundary while testing is in progress.” However, the outage group responsible for changing tagging boundaries did not include tags to isolate the Transformer RTX-XSR1F sudden overpressure trip relay from the RSS 2 protection circuit. Because this finding was of very low safety significance (Green) and was documented in the licensee's corrective action program as CR-RBS-2003-03456, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy, NUREG-1600 (NCV 50-458/2004005-03).

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors verified, by witnessing and reviewing test data, that three risk-significant system and component surveillance tests met Technical Specifications, USAR, and procedure requirements. The inspectors ensured that surveillance tests demonstrated that the systems were capable of performing their intended safety functions and provided operational readiness. The inspectors specifically: (1) evaluated surveillance tests for preconditioning; (2) evaluated clear acceptance criteria, range, accuracy, and current calibration of test equipment; and (3) verified that equipment was properly restored at the completion of the testing. The inspectors observed and reviewed the following surveillance tests and surveillance test procedures (STP):

- STP-309-2001, "Division II Diesel Generator Operability Test," Revision 24, performed on October 14, 2004
- STP-208-3601, "A Steam Line MSIV's and Outboard Drain Valve Leak Rate Test and Inboard MSIV Leakage Test," Revision 6, performed on October 26, 2004
- STP-057-3800, "Local Leak Rate - Outage Summation," Revision 13, performed on November 15, 2004

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

During the week of October 25, 2004, the inspectors reviewed temporary plant Alteration 2004-0049-00, installed October 22, 2004, to provide temporary power to the rod control and information system. Specifically, the inspectors: (1) reviewed the temporary modification and its associated 10 CFR 50.59 screening against the system's design basis documentation, including the USAR and Technical Specifications; (2) verified that the installation of the temporary modification was consistent with the modification documents; (3) verified that plant drawings and procedures were updated; and (4) reviewed the postinstallation test results to confirm that the actual impact of the temporary modification on the affected system had been adequately verified.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed the emergency preparedness practice exercise for the upcoming full scope exercise conducted on April 20, 2004, in both the simulator and technical support center to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors also evaluated the licensee assessment of classification, notification, and protective action recommendation development during the practice exercise in accordance with plant procedures and NRC guidelines. The following procedures and documents were reviewed during the assessment:

- EIP-2-001, "Classification of Emergencies," Revision 12
- EIP-2-006, "Notifications," Revision 30
- EIP-2-007, "Protective Action Guidelines Recommendations," Revision 19
- EP-M-04-034, "Drill Evaluation Report, ERO Team D," dated August 9, 2004
- CR-RBS-2004-1202, Protective action recommendation during April 20 practice exercise did not match drill scenario

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope

This area was inspected to assess the licensee's performance in implementing physical and administrative controls, including worker adherence to these controls, for airborne radioactivity areas, radiation areas, high radiation areas, and very high radiation areas. The inspectors used the requirements in 10 CFR Part 20, the Technical Specifications, and the licensee's procedures required by the Technical Specifications as criteria for determining compliance. During the inspection, the inspectors interviewed the radiation protection manager, radiation protection supervisors, and radiation workers. The inspectors performed independent radiation dose rate measurements and reviewed the following items:

- Performance indicator (PI) events and associated documentation packages reported by the licensee in the occupational radiation safety cornerstone
- Controls (surveys, postings, and barricades) of three radiation, high radiation, and airborne radioactivity areas
- Radiation work permit procedure, engineering controls, and air sampler locations
- Conformity of electronic personal dosimeter alarm setpoints with survey indications and plant policy; workers' knowledge of required actions when their electronic personnel dosimeter noticeably malfunctions or alarms
- Barrier integrity and performance of engineering controls in two potential airborne radioactivity work areas
- Physical and programmatic controls for highly activated or contaminated materials (nonfuel) stored within the spent fuel storage pool
- Self-assessments and audits related to the access control program since the last inspection
- Corrective action documents related to access controls
- Licensee actions in cases of repetitive deficiencies or significant individual deficiencies
- Radiation work permit briefings and worker instructions
- Adequacy of radiological controls such as required surveys, radiation protection job coverage, and contamination controls during job performance
- Dosimetry placement in high radiation work areas with significant dose rate gradients
- Changes in licensee procedural controls of high dose rate - high radiation areas and very high radiation areas
- Controls for special areas that have the potential to become very high radiation areas during certain plant operations
- Posting and locking of entrances to all accessible high dose rate - high radiation areas and very high radiation areas

- Radiation worker and radiation protection technician performance with respect to radiation protection work requirements

Either because the conditions did not exist or an event had not occurred, no opportunities were available to review the following items:

- Adequacy of the licensee's internal dose assessment for any actual internal exposure greater than 50 millirems committed effective dose equivalent

- Licensee event reports (LERs) and special reports related to the access control program since the last inspection

The inspectors completed 21 of the required 21 samples.

b. Findings

Introduction. The inspectors reviewed a Green, self-revealing NCV of Technical Specification 5.7.3. Three workers were exposed to unanticipated radiation levels of approximately 1,700 millirems per hour because the licensee's radiation protection technicians failed to identify and control an existing high radiation area with dose rates greater than 1,000 millirems per hour in the drywell.

Description. On October 31, 2004, three workers entered the drywell to perform maintenance activities on valves located on the 82-foot elevation. The three workers' electronic alarming dosimeters unexpectedly alarmed when they were exposed to unanticipated radiation levels of approximately 1,700 millirems per hour. Subsequent surveys at the source of radiation around Valve RCS-V-3009 measured 6,000 millirems per hour on contact and 2,000 millirems per hour at 30 centimeters. The area was not barricaded or conspicuously posted. It was not practical to lock the area; however, it did not have a flashing light activated as a warning device. The licensee determined that the three workers received 84, 85, and 95 millirems, respectively.

Analysis. The failure to control access to a high radiation area is a performance deficiency. The finding is more than minor because it is associated with the occupational radiation safety cornerstone attribute of exposure control and affected the cornerstone objective, because not controlling locked high radiation areas could increase personal exposure.

Since this occurrence involved workers' unplanned, unintended dose or potential for such a dose that could have been significantly greater as a result of a single minor, reasonable alteration of circumstances, this finding was evaluated with the occupational radiation safety significance determination process. The inspectors determined that the finding was of very low safety significance (Green) because it did not involve (1) ALARA planning and controls, (2) an overexposure, (3) a substantial potential for overexposure, or (4) an impaired ability to assess dose.

Enforcement. Technical Specification 5.7.3.a states, in part, that for individual high radiation areas with radiation levels greater than or equal to 1,000 millirems per hour that are accessible to personnel, that are located within large areas such as reactor containment, where no enclosure exists for purposes of locking, or that is not continuously guarded, and where no enclosure can be reasonably constructed around the individual area, that area shall be barricaded and conspicuously posted, and a flashing light shall be activated as a warning device. The licensee violated this requirement when it did not properly control the high radiation area with dose rates greater than 1,000 millirems per hour.

Because the failure to control a high radiation area was determined to be of low safety significance (Green) and was entered into the licensee's corrective action program as CR-RBS-2004-03551, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy, NUREG-1600 (NCV 05000458/2004005-04).

4. OTHER ACTIVITIES

4OA1 PI Verification (71151)

a. Inspection Scope

The inspectors sampled licensee submittals for the PIs listed below for the period from October 2003 through September 2004. To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Indicator Guideline," Revision 2, were used to verify the basis in reporting for each data element.

Mitigating Systems Cornerstone

- safety system unavailability, high pressure injection system
- safety system unavailability, RHR system

The inspector reviewed the licensee's PI technique sheets to determine whether the licensee satisfactorily identified the required data reporting elements. This data was compared with the data reported to the NRC since the last verification inspection was conducted. The inspectors reviewed the information reported in LERs and sampled the maintenance rule database, portions of operator log entries, and portions of limiting conditions for operation log entries to verify the accuracy of the data reporting elements, the licensee's basis for crediting system availability, and the calculation of the average system unavailability for the previous four quarters. The inspectors also interviewed licensee personnel associated with the PI data collection, evaluation, and distribution.

Occupational Radiation Safety Cornerstone

- Occupational Exposure Control Effectiveness PI

Licensee records reviewed included corrective action program records for Technical Specifications required locked high radiation areas, very high radiation areas as defined in 10 CFR 20.1003, and unplanned exposure occurrences from March 2003 to confirm that any occurrences were properly recorded as PIs as defined in NEI 99-02. Controlled access area exits with exposures greater than 100 millirems were reviewed, and selected examples were examined to determine whether they were within the dose projections of the governing radiation exposure permits. The inspectors interviewed licensee personnel that were accountable for collecting and evaluating the PI data. In addition, the inspectors toured plant areas to verify that high radiation, locked high radiation, and very high radiation areas were properly controlled.

Public Radiation Safety Cornerstone

- Radiological Effluent Technical Specifications/Offsite Dose Calculation Manual Radiological Effluent Occurrences

Licensee records reviewed included radiological effluent release program corrective action records and annual effluent release reports documented since March 2003 to determine if any liquid or gaseous effluent releases resulted in events that exceeded the PI thresholds. The inspectors interviewed licensee personnel that were accountable for collecting and evaluating the PI data.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

1. Loss of offsite power to Division I ESF Switchgear and start of the Division I emergency diesel generator during RFO-12

a. Inspection Scope

The inspectors reviewed the circumstances surrounding the October 31, 2004, loss of offsite power to Division I ESF 4160 Vac switchgear and start of the Division I emergency diesel generator, during preparations for the RFO-12 Division I integrated ECCS test. The inspectors interviewed electrical maintenance technicians and supervisors and the ECCS test coordinator, reviewed Procedure STP-309-0601, “Division I 18 Month ECCS Test,” Revision 22, and evaluated CR-RBS-2004-3518 written to document the event. Attributes evaluated during the inspectors’ review of the licensee’s evaluation of this issue included: (1) consideration of extent of condition, generic implications, and previous occurrences, and (2) classification and prioritization of the resolution of the problem commensurate with its safety significance. The inspectors also reviewed the following documents as part of this inspection:

- Administrative Procedure ADM-0023, "Conduct of Maintenance," Revision 17A
- CR-RBS-1994-0728, [Division III] HPCS bus feeder breaker tripped and Division III diesel generator started
- LER-1994-013-00, "Division III Diesel Generator Start Most Likely Due to Personal Error"
- CR-RBS-1999-0630, [Division III bus] feeder breaker tripped, Division III diesel generator output breaker closed and Division III diesel generator carried the Division III bus
- LER-1999-008-00, "Unplanned Automatic Closure of Division III Diesel Generator Output Breaker Due to Loss of Normal Power to Division III Switchgear During Testing"
- Engineering Department Standard EDS-EE-001, "Banana Jack Standard," Revision 3

h. Findings and Observations

Introduction. The inspectors identified a self-revealing NCV of Technical Specification 5.4.1.a. that was of very low safety significance (Green). During preparation for Division I integrated ECCS testing, a technician inadvertently made contact with the wrong terminal on an undervoltage relay, which tripped the preferred offsite power feeder breaker for the Division I ESF 4160 Vac switchgear and started the Division I emergency diesel generator.

Description. During pretest preparations for STP-309-0601, at step 7.2.11.2, an electrical maintenance technician installed a jumper on the back of an undervoltage relay in the Division I ESF 4160 Vac switchgear. This step allowed for bypassing the degraded voltage time delay trip of the relay. While adjusting the alligator clip on Terminal 5 of the relay, Terminal 4 was inadvertently contacted. This resulted in an immediate undervoltage trip of the relay. The preferred offsite power feeder breaker tripped and the Division I emergency diesel generator started and powered the bus.

The licensee stopped test preparations, investigated the cause of the event, and notified the NRC with Operating Event Report 41164. During the human performance event review, the licensee determined that the jumper was installed on relay Terminal 5 without taping over the adjacent Terminal 4. This was not in accordance with Procedure ADM-0023, "Conduct of Maintenance," Section 8.5, which stated, when performing high risk maintenance, evaluate the applicability of error reduction techniques such as "taping of adjacent leads/contact points."

The inspectors interviewed the technician who made the error. He stated that he was not aware that contacting the adjacent terminal would cause the undervoltage relay to trip. He stated that he was not aware of the expectation to tape the adjacent terminal in this situation and that the test procedure did not have a caution alerting technicians that contacting the adjacent terminal would trip the relay. He also said that he was aware of a program to install banana jacks on test points, such as the ones used during this procedure step, as an error prevention technique. No banana jacks were installed on this relay.

The inspectors determined that there were also problem identification and resolution aspects to this finding. The licensee determined, during their initial review of the broken or ineffective barriers that allowed the event to occur, that ineffective or incomplete corrective actions were taken in response to two similar events during Division III ECCS testing. Suggested corrective actions in CR-RBS-1994-0728 and -1999-0630 included: (1) maintenance, operations, and system engineering should evaluate STPs for the use of banana jacks; (2) each group should reinforce that banana jacks could be installed to facilitate verification, testing, and maintenance of electrical and instrumentation circuits; and (3) the groups should work together to develop a generic philosophy for where banana jacks should be installed. The inspectors determined that, had the licensee applied the corrective actions for two similar errors during performance of Division III ECCS testing to the Division I integrated ECCS test, the possibility of the error that caused the October 31, 2004, event would have been reduced significantly.

<u>Analysis</u> The inspectors determined that the inadvertent contact of the wrong terminal on the Division I ESF switchgear undervoltage relay was a performance deficiency (human performance error - personnel). Also ineffective implementation of corrective actions for similar errors contributed to the performance deficiency (problem identification and resolution - implementation of corrective actions). The finding was more than minor because it was associated with the initiating event cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions, namely a partial loss of offsite power. The inspectors evaluated the finding using IMC 0609, Appendix G, “Shutdown Operations Significant Determination Process,” Attachment 1, Checklist 7, “BWR Refueling Operations with RCS Level greater than 23 feet.” The finding was only of very low safety significance (Green) because it did not cause a loss of shutdown cooling and did not compromise the ac power guidelines that: (1) one qualified circuit of offsite power remained operable; (2) at least one emergency diesel generator remained operable; and (3) necessary portions of the ac electrical power distribution systems remained operable.

<u>Enforcement</u>. The inspectors determined that this finding was a violation of Technical Specification 5.4.1.a. which states, in part, that procedures shall be implemented and maintained for the activities covered in Regulatory Guide 1.33, Revision 2, Appendix A. Section 9.e of Appendix A refers to general procedures for the control of maintenance activities. The licensee failed to evaluate the applicability of error reduction techniques, such as “taping of adjacent leads/contact points,” for the installation of jumpers in accordance with Procedure ADM-0023, “Conduct of Maintenance,” Revision 17A, Section 8.5. In addition, the licensee failed to install banana jacks on terminals on the

back of the undervoltage relay in the Division I ESF 4160 Vac switchgear, which are jumpered during the performance of Procedure STP 309-0603, in accordance with Procedure EDS-EE-001, "Banana Jack Standard," Revision 3. Because the finding was of very low safety significance (Green) and was entered into the licensee's corrective action program as CR-RBS-2004-3518, this violation is being treated as an NCV, consistent with Section IV.A of the NRC Enforcement Policy, NUREG-1600 (NCV 0050458/2004005-05).

2. Rainwater leaked from auxiliary building roof onto Division I auxiliary building 480 Vac ESF switchgear, causing loss of auxiliary building area unit Cooler HVR-UC11A

a. Inspection Scope

The inspectors investigated the circumstances surrounding the December 5, 2004, leak of rainwater from the auxiliary building roof onto Division I 480 Vac ESF Switchgear EJS-SWG2A as documented in CR-RBS-2004-4218. The inspectors reviewed CR-RBS-2004-0346 and problem identification and resolution NCV 05000458/2004002-02, which documented a February 5, 2004, auxiliary building roof leak that also affected Switchgear EJS-SWG2A. The inspectors also reviewed CR-RBS-2004-1083, an adverse trend CR written to address leaking roofs on a number of plant buildings. Attributes evaluated, during the inspectors' review of the licensee's problem evaluation and corrective actions taken as part of these CRs, included: (1) consideration of extent of condition, generic implications, and previous occurrences, (2) classification and prioritization of the resolution of the problem commensurate with its safety significance and (3) Identification of corrective actions which are appropriately focused to correct the problem.

b. Findings and Observations

Introduction. The inspectors identified a self-revealing NCV of 10 CFR Part 50, Appendix B, Criterion XVI, for the licensee's failure to take timely and effective corrective action to prevent recurrence of rainwater leakage from the auxiliary building roof onto the Division I auxiliary building 480 Vac ESF switchgear, causing a loss of auxiliary building area unit Cooler HVR-UC11A.

Description. On December 5, 2004, 4 days after a heavy rainstorm, rainwater leaked through the auxiliary building roof onto auxiliary building 480 Vac ESF Switchgear EJS-SWGR2A. As a result, water got into the breaker supplying auxiliary building area unit Cooler HVR-UC11A and grounded an internal control circuit, causing smoke and a humming noise. Operators responded by pulling the breaker control power fuses, which disabled the breaker, stopped damage to the control circuit, and removed the ground from Switchgear EJS-SWGR2A control power. Electrical technicians removed the breaker from the switchgear and replaced it with a spare breaker that was properly set up and tested for this use.

Investigation into the source of water determined that rainwater was accumulating inside the auxiliary building fresh air intake structure on the roof and leaking through seals along the air inlet ductwork onto Switchgear EJS-SWGR2A. The inspectors determined that this was a repeat of a February 5, 2004, leak documented in CR-RBS-2004-0346 and problem identification and resolution NCV 05000458/2004002-02.

The licensee took several long-term corrective actions for the February 5 leak. First, they sealed the floor of the fresh air intake structure with an improved sealing material. However, the sealing material contracted during cold weather between a December 1, 2004, rainstorm and the leak 4 days later. Second, maintenance support personnel wrote an engineering request to install louvers over the 8 foot by 9 foot opening in the fresh air intake structure on February 9, 2004. The engineering response to perform a plant modification to install the louvers was not completed until July 20, 2004. WO 47657 to install the louvers was approved on July 19, 2004. The purchase order for the louvers was processed on July 23, 2004. The lovers were received on site on November 16, 2004. The actual work to install the louvers was not started until December 6, 2004, after the leak and breaker damage. As a compensatory measure while awaiting the installation of the louvers, maintenance support personnel inspected the fresh air intake structure after each rainstorm and, on several occasions, removed as much as 4 inches (40 gallons) of water from its floor (actually the auxiliary building roof). After the December 1 rainstorm, maintenance support personnel did not remove the water from the fresh air intake structure floor due to other work priorities. The inspectors noted that no temporary cover was placed on the auxiliary building roof to deflect water away from the opening pending installation of the permanent louvers. The inspectors determined that untimely (installation of louvers in the opening on the side of the fresh air intake structure) and ineffective (floor sealing, periodic rainwater removal from the structure) corrective actions were responsible for the recurrence of the February 5 leak on December 5, 2004, which led to rainwater leaking onto Switchgear EJS-SWGR2A and damage to the supply breaker for unit Cooler HVR-UC11A.

Analysis. The inspectors determined that the licensee's failure to take timely and effective corrective action to stop rainwater leaks from the auxiliary building roof onto Switchgear EJS-SWG2A was a performance deficiency that caused the loss of unit Cooler HVR-UC11A. Unit Cooler HVR-UC11A provided cooling for safety-related equipment on the 141 foot elevation of the auxiliary building including Switchgear EJS-SWG2A and other safety-related Division I motor control centers. The finding was more than minor because, if left uncorrected, rainwater leaks from the auxiliary building roof could lead to the loss of other Division I safety-related equipment and motor control centers powered by Switchgear EJS-SWG2A. The inspectors reviewed the finding using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." Based on the Phase 1 screening, the inspectors determined that the finding was of very low safety significance (Green) because the short-term loss of unit Cooler HVR-UC11A did not cause an actual loss of safety function of any train of Technical Specification risk significant equipment and was not potentially risk significant due to a seismic, flooding, or severe weather initiating event. This finding had crosscutting aspects of problem identification and resolution in that previous actions taken to correct the deficiency were ineffective (corrective action).

Enforcement. The inspectors determined that the failure to take timely and effective actions to prevent rainwater from leaking onto Switchgear EJS-SWGR2A was a violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action.” Because this finding was of very low safety significance (Green) and was entered into the licensee’s corrective action program as CR-RBS-2004-4218, this violation is being treated as an NCV, consistent with Section IV.A of the NRC Enforcement Policy, NUREG-1600 (NCV 0500458/2004005-06).

3. Semiannual Trend Review

a. Inspection Scope

The inspectors performed a 6-month review of the licensee’s corrective action program and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspector’s review was focused on repetitive issues and also considered the results of daily inspector screening of CRs, licensee trending efforts, and licensee human performance results. The inspector’s review considered the 6-month period of October 2004 through December 2004. Inspectors also reviewed 32 CRs associated with human performance errors that occurred during RFO-12. The CR numbers are listed in the attachment. The inspectors compared and contrasted their results with the results contained in the licensee’s CR used to capture the extent of the multiple human performance errors that occurred during RFO-12.

The inspectors also evaluated the CRs against the requirements of the licensee’s corrective action program as specified in licensee Procedure LI-102, “Corrective Action Process,” Revision 1 and 10 CFR Part 50, Appendix B.

b. Findings and Observations

There were no findings of significance identified. The inspectors reviewed the CRs and human performance evaluations of 24 human performance errors during RFO-12. The inspectors found that there were a number of human performance errors that resulted in varying degrees of damage to plant equipment, unexpected starts of ESF equipment, and in some cases injuries to workers. Some examples of human performance error were:

- Four personal safety violations, one of which resulted in a worker breaking his foot jumping down from the bed of a vehicle

- Four different occurrences when the polar crane, core refueling platform, or fuel handling bridge were moved, damaging equipment, and one case where a worker’s protective clothing was ripped

- Three tagout restoration errors which resulted in the start of an ESF area cooler and an emergency diesel generator and overtorquing a motor-operated valve

- Three procedure violations which resulted in a fuel bundle being left in an unacceptable storage location, unexpected start of an ESF air conditioner during loss of power testing, and invalidation of shutdown margin data during startup

- Improper installation of jumpers that resulted in overtorquing a motor-operated valve, loss of an ESF 4160 Vac switchgear, start of the emergency diesel generator, and an unexpected actuation of the alternate rod insertion circuit

- Improper troubleshooting which resulted in the loss of the protected division offsite power supply and shutdown cooling (See Section 1R20.)

The licensee held a number of safety standdowns during the outage to refocus plant workers on personal and equipment safety. In several cases, the licensee identified procedural weaknesses that contributed to the human errors. The inspectors noted some common errors: (1) lack of peer- and self-checking, (2) proceeding with a task while uncertain of the possible outcome, (3) lack of adequate supervision of contractor personnel and resource sharing workers from other licensee plants, and (4) lack of a clear understanding of worker's and supervisor's duties and responsibilities.

4. <u>Cross-References to Problem Identification and Resolution Findings Documented Elsewhere</u>

Section 4OA3 describes a problem identification and resolution finding for the failure to identify and correct a root cause for a turbine and reactor trip which led to a subsequent turbine and reactor trip during turbine control valve testing

Section 4OA5 describes a problem identification and resolution finding for the failure to properly identify and correct inadequate maintenance performed on station switchyard beakers that led to a reactor scram and partial loss of offsite power.

4OA3 <u>Event Followup (71153)</u>

<u>(Closed) LER 05000458/2003-008-00</u>. Automatic Reactor Scram During Main Turbine Control Valve Testing Due to Control System Malfunction

a. <u>Inspection Scope</u>

The inspectors reviewed the subject LER and the licensee's analysis of the event as documented in CR-RBS-2003-3203. The inspectors verified the accuracy of the LER and reviewed: (1) the licencee's determination of the root cause and other causal factors, (2) corrective action documentation of other reactor trips related to electrostatic charge induced signal errors during turbine control valve testing, (3) the licensee's determination of extent of condition, and (4) the appropriateness of corrective actions taken and planned. The inspectors reviewed the following documents as part of this inspection:

- Nuclear Management Manual EN-LI-118, “Root Cause Analysis Process,” Revision 0

- CR-RBS-2001-0523, “Unplanned Reactor Scram During Turbine Control Valve Testing”

- LER 2001-001-00, “Unplanned Reactor Scram During Turbine Control Valve Testing”

- LER 2003-008-00, “Automatic Reactor Scram During Main Turbine Control Valve Testing Due to Control System Malfunction”

b. Findings and Observations

Introduction. The inspectors identified a self-revealing finding based on the licensee’s failure to adequately identify and correct the root cause of the April 21, 2001, turbine and reactor trip so as to prevent recurrence. This failure resulted in a subsequent turbine and reactor trip on September 22, 2003. The finding was more than minor because it was associated with the equipment performance attribute of the initiating events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations.

Description. On September 22, 2003, while performing scheduled tests on the main turbine control valves, an automatic reactor trip occurred. The trip was in response to a high reactor vessel pressure signal on reactor protection system Channel A and a turbine control valve fast closure signal on reactor protection system Channel B. The licensee identified that the turbine speed control system sensed a false high acceleration rate signal, which rapidly closed the turbine control valves. This caused reactor steam pressure to rise to a maximum value of 1108 psig.

An inspection of Turbines 1 and 2 bearing vibration probes, by the licensee, indicated the presence of babbit material. This strongly suggested that electrostatic arcing (electrolysis) had occurred. Based on this and other evaluations and tests, the licensee concluded that the cause of the false high acceleration rate signal was due to the primary and backup speed probes being sensitive to electromagnetic interference associated with electrostatic arcing. This sensitivity caused the false high acceleration rate, closure of the turbine control valves, and the subsequent reactor trip.

As part of the licensee’s postevent evaluation, the licensee identified that a similar turbine and reactor trip had occurred on April 21, 2001, while turbine control valve testing was being performed. The licensee concluded at that time that the root cause of that event was due to rotor dynamics of the high pressure turbine during control valve testing. This conclusion was revised and control valve testing was suspended when, during the subsequent refueling outage, the Turbine 2 bearing was found to have extensive damage (to the upper shell) due to electrolysis, and the backup speed sensor cable was found to be also damaged. The licensee concluded at that time that the sensitivity of the damaged cable to electrostatic arcing was the primary cause of the April 21, 2001, event.

The licensee reviewed the root cause analysis performed for CR-RBS-2001-0523 and determined that the root cause analysis did not adequately identify the reason for the rapid acceleration of the turbine, which resulted in inadequate corrective actions. These corrective actions did not preclude recurrence of the event on September 22, 2003. The licensee concluded that this failure was the result of a breakdown in management oversight of the investigation of the April 21, 2001, event.

Analysis. The inspectors determined that the failure by the licensee to adequately identify the root cause of the April 21, 2001, event, and to take effective corrective actions to prevent electrostatic arcing from affecting the primary and backup speed probes, was a performance deficiency. The inspectors determined that this performance deficiency led directly to the recurrence of the event on September 22, 2003. This finding does not have an immediate safety concern, did not have any actual safety consequences, and did not impact the NRC's ability to perform its regulatory function and there were no willful aspects of the violation. The finding was more than minor because it was associated with the equipment performance attribute of the initiating events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The inspectors reviewed the finding using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." Based on the Phase 1 screening of the finding, the inspectors determined that the finding was of very low safety significance (Green) because it did not affect loss of coolant accident initiators, did not contribute to increasing the likelihood of both an initiating event and affecting mitigating equipment, and did not increase the likelihood of a fire or flood. This finding had problem identification and resolution crosscutting aspects regarding ineffective root cause determinations.

Enforcement. The inspectors determined that the failure to adequately identify and correct the root cause of the April 21, 2001, turbine and reactor trip so as to prevent recurrence, resulting in a subsequent turbine reactor trip on September 22, 2003, was a finding, although no violation of regulatory requirements occurred. This issue was entered into the licensee's corrective action program as CR-RBS-2003-3203 (FIN 05000458/2004005-07).

4OA4 Crosscutting Aspects of Findings

Cross-Reference to Human Performance Error Findings Documented Elsewhere

Section 1R08 describes a human performance error regarding failure to follow procedure and verify interpass temperatures while welding on an ASME Class 1 valve.

Section 1R20 describes a human performance error regarding failure to reset a tripped transformer sudden pressure sensor during troubleshooting which led to a loss of the protected offsite power supply during RFO-12.

Section 4OA2 describes a human performance error regarding failure to properly apply an electrical jumper to an undervoltage relay during preparation for integrated ECCS testing, which led to the loss of the Division I offsite power supply during RFO-12.

4OA5 Other Activities

(Closed) Unresolved Item (URI) 05000458/2004004-01. Failure to identify and properly evaluate deficient conditions related to switchyard breakers

Introduction. The inspectors identified a self-revealing finding of very low safety significance (Green) concerning the failure of the licensee to properly identify and correct inadequate maintenance performed on station switchyard beakers. On three occasions the licensee failed to properly evaluate slow switchyard breaker opening and failed to identify the potential for similar failures. These problem identification and resolution failures contributed to two simultaneous offsite transmission line failures becoming a main generator trip and reactor scram with a loss of the Division II offsite power supply.

Description. On August 15, 2004, a transmission line tower failure on Port Hudson Line 353 into the River Bend Station Fancy Point Switchyard failed to properly isolate due to slow opening of switchyard Breaker 20650. This caused backup breaker protection relays to deenergize the north 230 kV bus. Two subsequent slow breaker failures caused the line fault to be sensed by the station’s main transformer ground fault protection relay, resulting in a main generator lockout, generator load reject reactor scram, and main turbine trip. The original transmission line tower failure also caused a momentary ground fault on ENJAY Line 352 into the station switchyard. The isolation of this second ground fault opened two more switchyard breakers, causing a loss of power from the south 230 kV bus to the offsite power supply for half of the balance of plant electrical loads and the Division II ESF 4.16 kV switchboard. The Division II emergency diesel generator started and powered the Division II ESF switchboard.

The inspectors determined that, had the affected switchyard breakers operated properly to isolate the two simultaneous transmission line ground faults: the first ground fault would have been isolated from the station’s main transformer, the reactor scram would not have occurred, and power would not have been lost to the Division II ESF switchboard.

The licensee’s root cause analysis identified three occasions when slow opening of switchyard breakers resulted in deenergizing the north or south 23 kV bus at Fancy Point and one reactor scram. Two of the three previous problems were a result of slow opening of the same switchyard breakers that operated slowly on August 15. All of the switchyard breakers which operated slowly were McGraw-Edison 230 kV oil circuit breakers.

LER 50-458/89-042 and CR-RBS-1989-1245 documented a ground fault on a 230 kV transmission line feeding the station switchyard. Because switchyard Breaker 20745 opened slowly, the ground fault was sensed by the station's main transformer fault protection relays, which resulted in a main generator lockout, a generator load reject reactor scram, and a main turbine trip on December 1, 1989. The breaker was inspected and speed time tested after the event. Nothing was found to indicate why the breaker operated slowly and no corrective actions were taken. There was no indication that inspection or testing was done on the other seven similar switchyard breakers.

CR-RBS-2002-2094 documented a December 31, 2002, lightning strike on one transmission line feeding the station switchyard. Because switchyard Breaker 20660 opened slowly, backup breaker protection relays deenergized the south 230 kV bus. System engineering, electrical maintenance, and the transmission maintenance group inspected the breaker. Hardened grease was found on the breaker operating mechanism. The grease was replaced and the breaker tested as satisfactory and was returned to service. No other inspection or testing was done on the other seven similar switchyard breakers. System engineering personnel requested that the transmission maintenance group increase breaker maintenance frequency for all McGraw-Edison breakers in the station switchyard.

CR-RBS-2004-1567 documented a static line failure that resulted in a ground fault on one transmission line feeding the station switchyard on June 1, 2004. Because switchyard Breaker 20695 opened slowly, backup breaker protection relays deenergized the north 230 kV bus. System engineering and electrical maintenance worked with the transmission maintenance group to test the remaining McGraw-Edison switchyard breakers for operating times. System Engineering and the transmission maintenance group agreed to pursue the root cause of the slow breaker opening. Further inspection of the slow opening breakers was scheduled for the refueling outage in October 2004 based on satisfactory testing of six of the McGraw-Edison switchyard breakers. CR-RBS-2004-1893 was written to include testing of the last two breakers in the work planning schedule.

The speed testing performed on the switchyard breakers required that they be isolated from their transmission lines. In order to open a switchyard breaker's disconnect switches to isolate the breaker and attach the test equipment, the actual breaker must first be opened. Opening the breaker before speed testing effectively preconditioned the breaker operating mechanism, causing the speed test to be a false indication of actual breaker condition.

The inspectors determined that the licensee had ample opportunity to identify and evaluate the potential for common cause failure of the eight McGraw-Edison breakers in the station's switchyard. Two of the breakers that malfunctioned on August 15, Breakers 20745 and 20695, had previously failed, and diagnostic speed testing of the remaining breaker that malfunctioned on August 15 was ineffective because of preconditioning. Subsequent breaker maintenance since August 15 determined that in each case hardened grease and improper lubrication were responsible for slow breaker opening. A different method of speed testing the breakers when they are first opened (and not preconditioned) has been put in place for further switchyard breaker diagnostic testing.

Analysis. The inspectors determined that the licensee failed to: (1) identify a deficient condition due to preconditioned speed testing of the McGraw-Edison breakers and (2) properly evaluate three similar occurrences of the McGraw-Edison switchyard breakers operating slowly. As a result, three switchyard breakers opened slowly on August 15, 2004. A transmission line ground fault that should have been isolated from the switchyard remained connected to the main transformer long enough to cause a main generator lockout and reactor scram. Additionally, because of the slow breaker opening that deenergized the north 230 kV bus, a coincident transmission line fault resulted in a loss of power to half of the balance of plant loads and the Division II ESF switchboard.

This self-revealing finding was more than minor because it was associated with the initiating event cornerstone objective to limit those events that upset plant stability (resulted in a reactor scram) and challenge a critical safety function during power operations (loss of offsite power to Division II ESF switchboard and half of the balance of plant loads). The inspectors evaluated the finding using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." Because the finding contributed to the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available, the finding required a Phase 2 analysis. As a result of the Phase 2 analysis, the inspectors referred the final significance determination of the finding to the regional senior reactor analyst.

The senior reactor analyst performed a Phase 3 analysis of the event. The factors that contributed to the result of that analysis included: (1) the dominant sequence was a transient with a loss of power to a vital bus; (2) the consequences of the finding were bounded by a complete loss of offsite power; (3) the history of single slow switchyard breaker operation; (4) the design and layout of the station switchyard; and (4) the possibility of recovery from either a partial or complete loss of offsite power given the conditions that led to the events of August 15, 2004. The result was that the finding was of very low safety significance (Green) (FIN 05000458/2004005-08). This finding had crosscutting aspects of problem identification and resolution in that the extent of the condition was not properly evaluated (evaluation).

Enforcement. No violation of NRC requirements was identified because the slow acting breakers did not directly supply the Technical Specification required offsite power supplies; therefore, they are not covered by 10 CFR Part 50, Appendix B.

4OA6 Meetings, Including Exit

Exit Meetings

On October 29, 2004, the inspectors presented the radiation safety inspection results to Mr. T. Trepanier, General Manager, Plant Operations, and other members of licensee management who acknowledged the findings. Additionally, on November 4, 2004, a telephonic exit was conducted with Mr. M. Boyle and other members of licensee management.

On October 29, 2004, the inspector presented the inservice inspection results to Mr. T. Trepanier, General Manager, Plant Operations, and other members of licensee management. Licensee management acknowledged the inspection results. On November 10, 2004, a subsequent telephonic exit was held with Mr. D. Lorfing, Acting Manager, Licensing to discuss the characterization of findings.

On December 3, 2004, the inspector presented the biennial heat sink performance inspection results to you and other members of licensee management. Licensee management acknowledged the inspection findings. Proprietary information was reviewed by the inspector and left with the licensee at the end of the inspection.

On January 4, 2005, the inspectors presented the integrated inspection results to you and other members of licensee management. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee-Identified Violations

The following findings of very low safety significance (Green) were identified by the licensee as violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

(1) Technical Specification 5.7.2 requires, in part, that high radiation areas with dose rates greater than 1,000 millirems per hour shall be provided with locked or continuously guarded doors to prevent unauthorized access. On May 1, 2004, the radiation protection staff identified a gap in the deck plates on the horizontal portion of the main generator housing. The gap was large enough for a person to enter, travel underneath the shield wall, and enter a posted locked high radiation area with radiation levels in access of 1,000 millirems per hour. The licensee described this event in CR-RBS-2004-01287.

The finding had a very low safety significance (Green) because it did not involve: (1) an ALARA finding, (2) an overexposure, (3) a substantial potential for an overexposure, or (4) an impaired ability to assess dose.

(2) Technical Specification 5.7.1 requires, in part, that entry into high radiation areas shall be controlled by the issuance of a radiation work permit that requires a radiation monitoring device that continuously integrates the radiation dose rate in the area and alarms when preset integrated dose is received. Entry into such areas with this monitoring device may be made only after dose rate levels have been established and personnel have been made aware of them.

a. On September 23, 2003, the radiation protection staff identified that three unmonitored workers entered a high radiation area on the east side of the Turbine Building, at the 154-foot elevation, logged on to an improper radiation work permit, and had not been briefed on the radiological conditions in the area. The workers were wearing electronic alarming dosimeters and received 2 millirems during the entry. The licensee described this event in CR-RBS-2004-02759.

b. On April 8, 2003, an individual entered into a high radiation area on the Reactor Building at the 186-foot elevation, without wearing an electronic dosimeter. The individual had left his dosimetry behind after dressing out to enter a contamination area. The licensee determined that the individual received 14 millirems during the high radiation area entry. The licensee described this event in CR-RBS-2003-1761.

The finding had a very low safety significance (Green) because it did not involve (1) an ALARA finding, (2) an overexposure, (3) a substantial potential for an overexposure, or (4) an impaired ability to assess dose.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

T. Aley, Manager, Planning and Scheduling/Outage
L. Ballard, Manager, Quality Programs
S. Belcher, Manager, Operations
M. Boyle, Manager, Radiation Protection
D. Burnett, Superintendent, Chemistry
C. Bush, Manager, Outage
J. Clark, Assistant Operations Manager - Shift
C. Forpahl, Manager, Corrective Actions
T. Gates, Manager, System Engineering
R. Godwin, Manager, Training and Development
H. Goodman, Manager, Design Engineering
P. Hinnenkamp, Vice President - Operations
G. Huston, Assistant Operations Manager - Staff
N. Jackson, Acting Director, Maintenance
A. James, Superintendent, Plant Security
R. King, Director, Nuclear Safety Assurance
J. Leavines, Manager, Emergency Planning
D. Lorfing, Acting Manager, Licensing
J. Malara, Director, Engineering
W. Mashburn, Manager, Programs and Components
J. McGhee, Manager, Plant Maintenance
T. Trepanier, General Manager - Plant Operations

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None.

Opened and Closed

05000458/2004005-01	NCV	Failure to control special processes such as welding in accordance with qualified welding procedures (Section 1R08)
05000458/2004005-02	NCV	Wide-range reactor water level indication did not respond, as expected by operators, following an unplanned reactor scram (Section 1R14)

05000458/2004005-03	NCV	Failure to revise a tagging boundary to support an emergent troubleshooting task resulted in a loss of protected division of offsite power and shutdown cooling (Section 1R20)
05000458/2004005-04	NCV	Failure to control a high radiation area in accordance with Technical Specification 5.7.3 (Section 2OS1)
05000458/2004005-05	NCV	Human performance error causes a loss of offsite power to Division I ESF Switchgear and start of the Division I emergency diesel generator during RFO-12 (Section 4OA2)
05000458/2004005-06	NCV	Rainwater leaked from auxiliary building roof onto Division I auxiliary building 480 Vac ESF switchgear, causing loss of a safety-related auxiliary building area unit (Section 4OA2)
05000458/2004005-07	FIN	Automatic reactor scram during main turbine control valve testing due to control system malfunction (Section 4OA3)
05000458/2004005-08	FIN	Failure to identify and properly evaluate deficient conditions related to switchyard breakers (Section 4OA5)

Closed

05000458/2003-008-00	LER	Automatic reactor scram during main turbine control valve testing due to control system malfunction (Section 4OA3)
05000458/2004004-01	URI	Failure to identify and properly evaluate deficient conditions related to switchyard breakers (Section 4OA5)

Discussed

None.

LIST OF DOCUMENTS REVIEWED

The following documents were selected and reviewed by the inspectors to accomplish the objectives and scope of the inspection and to support any findings:

Section 1R06: Flood Protection Measures

River Bend Station individual plant examination of external events

USAR Section 3.4.1, "Flood Protection"

USAR Table 3.4-1, " Structures, Penetrations, and Access Openings Designed for Flood Protection"

Table 3C.3-1, "Moderate Energy Systems Located in Buildings Containing Safe Shutdown Equipment"

Table 3C 3-2, "Maximum Leakage Rates for Each Building Containing Safe Shutdown Equipment"

Engineering Calculation G13.18.12.3*15, Internal Flooding Screening Analysis," Revision 0

Calculation PN-317, "Maximum Flood Elevations for Moderate Energy Line Cracks in Category I Structures," Revision 0

Emergency Operating Procedure, AOP-003, "Secondary Containment and Radioactive Release Control," Revision 13

Alarm Response Procedure, ARP-870-51, "P870 Alarm Response," Revision 15

Section 1R07: Heat Sink Performance

Calculations

PM-194, "Standby Cooling Tower Performance and Evaporation Losses Without Drywall Unit Coolers," Revision 7

GE Nuclear Energy Calculation 23A5462, "RHR Heat Exchanger Calculated Performance," Revision 1

GE Nuclear Energy Calculation 22A4206AJ, "RHR Heat Exchanger," Revision 1

G13.18.14.0*190-1, "Post-Accident Heat Load Development for Power Uprate Service Water Evaluations," dated July 24, 2000

PB-210, "Heat Gain for Containment Outside Drywell," Revision 2, Addenda B

G13.18.1.*061, "Auxiliary Building Design Basis Heat Loads and Unit Cooler Sizing Verification," Revision 3B

NESE 907-1, “Addendum to Cooling Coil Design Report for Auxiliary Building Unit Coolers at River Bend Station Unit 1,” dated August 19, 1991

G13.18.2.1*061, “Auxiliary Building Design Bases Heat Loads and Unit Cooler Sizing Verification,” Revision 3B

Condition Reports

1997-02139	2003-00983	2003-02413
2000-01540	2003-01013	2004-02107
2002-00376	2003-01240	2004-02117
2002-00478	2003-01310	2004-02122
2002-02090	2003-01724	2004-03207

Engineering Requests

ER-99-0148, “Uninsulation of Selected Sites in the RHR A & B Cubicle During Mode 1,” Revision 1

ER-99-0690, “Auxiliary Building Unit Cooler Performance at 95 Degrees F Service Water Temperature,” Revision 1

ER-2003-0608, “Install a Temporary Plastic Strip Door on Containment Equipment During Modes 4 & 5,” Revision 0

Procedures

PEP-0239, “Performance Monitoring Program for Residual Heat Removal Heat Changers E12-EB001A and E12-EB001C (Division 1),” Revision 2

PEP-0240, “Performance Monitoring Program for the RHR Heat Exchangers,” Revision 2

PEP-0249, “Chemical Cleaning of Plant Heat Exchangers,” Revision 1

TP-97-0006, “Flow Balance Design Flow Verification for the Standby Service Water and Normal Service Water System,” Revision 1

TP-00-0003, “RHR Division 2 Heat Exchanger Chemical Cleaning Procedure (Shell Side),” Revision 0

Work Orders

340390	350508	359965
343070	351843	363692
346906	353234	50688289
348612	354648	

Surveillance Tests

TP-97-0007, “RHR Division II Heat Exchanger Chemical Cleaning Procedure (Shell Side),” Revision 1, October 06, 1997

TP-97-0007, “RHR Division II Heat Exchanger Chemical Cleaning Procedure (Shell Side),” Revision 2, October 09, 1997

TP-00-0002, “RHR Division I Heat Exchanger Chemical Cleaning Procedure (Shell Side),” Revision 1, March 04, 2000

Miscellaneous

02 IR 20077, “Quality Control Inspection Report of Wall Thickness Measurements of Room Cooler HVR UC #3,” dated June 13, 2001

Design Specification 215.253, “Addendum to Cooling Coil Design Report for Auxiliary Building Unit Coolers at River Bend Station,” dated August 19, 1991

Report No. SIR-98-106, “Evaluation of the Effects of Excess Flow Through Unit Coolers at River Bend,” Revision 0

SDC-204, “Residual Heat Removal System Design Criteria System Number 204,” Revision 3

Section 1R08: Inservice Inspection Activities

Procedures

CEP-NDE-0404	“Ultrasonic Examination of Ferritic Piping Welds (ASME Section XI),” Revision 0
CEP-NDE-0421	“Manual Ultrasonic Weld/Wall Thickness Profile,” Revision 0
GE-UT-503	“Automated Ultrasonic Examination of the Shroud Assembly Welds,” Revision 12
GE-UT-504	“Ultrasonic Examination of Jet Pump Beams In Boiling Water Reactors,” Revision 9
GE-UT-511	“Automated Examination fo Core Spray Piping Welds Contained Within The Reactor Pressure Vessel,” Revision 12
LI-101	“10 CFR 50.59 Review Program,” Revision 3

NDE Activities Reviewed

System/Component ID	Weld Number/Cat	Exam Method	Review Type
Jet Pump 5	BWRVIP	UT	R/O
Jet Pump 6	BWRVIP	UT	R/O
Jet Pump 7	BWRVIP	UT	R/O
Jet Pump 8	BWRVIP	UT	R/O
Core Spray	Weld AP3A	UT	Records
Core Spray	Weld AP3AC	UT	Records
Core Spray	Weld AP5P	UT	Records
Core Spray	Weld AP5C	UT	Records
Reactor Core Isolation	Weld ICS-0524-SW053	UT	Records
Core Shroud	Weld H7 BWRVIP	UT	Observation
Feedwater Inlet Check Valve	ASME Section III	MT	Records
Feedwater	B21-AOVF032B (welding of new valve seat)	MT	Records

Miscellaneous

Technical Report: TR-105696-R6 (BWRVIP-03), "BWR Vessel and Internals Project, Reactor Pressure Vessel and Internals Examination Guidelines," Revision 6

Electric Power Research Institute (EPRI): EPRI TR-106740, dated July 1996, BWR Vessel and Internals Project, BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines (BWRVIP-18)

Calculation G13.18.10.2*129, Qualification of CRD Scram Discharge Volume Vent & Drain Piping for the Loads Imposed by Valve Opening and Closing, per CR-RBS-1895-0465, Revision 0

WO 50358808, Test Relief Valve E51-RVF018

Engineering Request ER-RB-2003-0159-000, Evaluation of Acceptability of Scram Discharge Volume Vent/Drain Valve Operation with Less Than 5 Second Differential, Revision 0

Procedure Action Request

PAR-STP-052-6301R13PR-12
PAR STP-052-6301R13PR-14

ASME Repair Replacement (Welding) RFO-11

Corrective Maintenance Action Item MAI 353716

Valve SWP-V155, Control Building Water Chiller Condenser B, service water recirculation line check valve (repair valve seat, weld lugs to valve body)

Condition Reports

CR-RBS-2002-00038	CR-RBS-2003-00594	CR-RBS-2003-01876
CR-RBS-2002-00548	CR-RBS-2003-00605	CR-RBS-2003-02808
CR-RBS-2003-00039	CR-RBS-2003-01353	CR-RBS-2003-03696
CR-RBS-2003-00189	CR-RBS-2003-01372	CR-RBS-2004-00747
CR-RBS-2003-00250	CR-RBS-2003-01431	CR-RBS-2004-03420
CR-RBS-2003-00504	CR-RBS-2003-01606	

Section 1R14: Personnel Performance during Nonroutine Plant Evolutions

Procedures

AOP-001, “Reactor Scram,” Revision 20
AOP-002, “Main Turbine and Generator Trips,” Revision 16
AOP-003, “Automatic Isolations,” Revision 21
AOP-005, “Loss Main Condenser Vacuum, Trip of Circulating Water Pump,” Revision 15
AOP-006, Condensate Feedwater Failures,” Revision 15
AOP-042, “Loss of Instrument Bus,” Revision 20
AOP-010, “Loss of RPS Bus,” Revision 14
EOP-001, “RPV Control,” Revision 16
EOP-002, “Primary Plant Control,” Revision 12
OSP-0019, “Electrical Bus Outages,” Revision 07

Miscellaneous

ER-98-0068-000-00, “Replace Recorders B21-R623A and B with digital paperless recorders,” dated July 7, 1998

Section 1R16: Operator Workarounds

Policies and Procedures

"Operator Workaround - Control Room Deficiency Program Guidelines," Revision 11

OPS Policy 30, "Operations Contingency Action Planning," Revision 0

Nuclear Management Manual EN-LI-111, "Operational Decision Making Issue Process," Revision 1

Miscellaneous Documents

Operator Work Around Report
Operator Burden report
Equipment Status Turnover Sheets
Daily Plant Status Reports
Operations Shift Turnover Sheets
List of Control Room Deficiencies
Tracking Limiting Conditions of Operations report

Section 1R19: Postmaintenance Testing (71111.19)

Work Orders

WO 50367904 02, Repack Valve E12-MOVF008, shutdown cooling suction isolation, conducted on November 6, 2004

WO 00033583 01, RHR Shutdown Cooling Suction Penetration KJB-Z20 Valve Leak Rate As-Found Test, conducted on November 5, 2004

WO 00033583 03, RHR Shutdown Cooling Suction Penetration KJB-Z20 Valve Leak Rate As-Left Test, conducted on November 7, 2004

WO 50687946 01, Stroke time test RHR Shutdown Cooling Suction valves, conducted November 14, 2004

WO 50687948 01, Shutdown cooling suction isolation valves pressure isolation test, conducted November 8, 2004

Procedures

STP-402-0202, "Main Control Room Air Conditioning Train B Operability Test," Revision 5, performed on January 9, 2003

OSP-0047, "Local Leak Rate Testing Implementation," Revision 3

Piping and Instrument Diagrams

PID-27-07A, “Residual Heat Removal,” Revision 35
PID-27-07B, “Residual Heat Removal,” Revision 38
PID-27-07C, “Residual Heat Removal,” Revision 25
PID-04-03C, “Condensate Makeup Storage and Transfer,” Revision 19

Section 1R20: Refueling and Outage Activities (71111.20)

Plant Procedures

GOP-0001, “Plant Startup,” Revision 45
GOP-0002, “Power Decrease, Plant Shutdown,” Revision 31
GOP-0003, “Scram Recovery,” [Post Trip Review], Revision 15
AOP-0027, “Fuel Handling Mishaps,” Revision 19
OSP-0037, “Shutdown Outage Protection Plan,” Revision 14
OSP-0038, “Protective Tagging Guidelines,” Revision 15
OSP-0041, “Alternate Decay Heat Removal,” Revision 08

Condition Reports

CR-RBS-2004-3488	CR-RBS-2004-3518	CR-RBS-2004-3546
CR-RBS-2004-3492	CR-RBS-2004-3523	CR-RBS-2004-3580
CR-RBS-2004-3499		

Miscellaneous Documents

Event Notification 41164, Automatic start of the Division 1 emergency diesel generator

Event Notification 41165, [Division II] emergency diesel generator automatic start

Diesel System Engineer e-mail to Operations: steps to restore Division 2 Diesel to Normal Standby without starting

Plant Manager e-mail to Site Vice President: RF-12 Loss of RSS 2 and Plant Recovery Assessments and Actions

Equipment Tagouts 311-RSS-2-001 and 311

Section 2OS1: Access Control to Radiologically Significant Areas

Radiation Work Permits

2004-1620 Perform walkdowns/take field measurements in main steam tunnel for permanent shielding design

2004-1800 RFO-12 refueling activities

2004-1912 RFO-12 remove/replace 16 SRVs

2004-1915 RFO-12 remove/replace LPRMs, including all support activities

2004-1933 RFO-12 ISI weld inspections in drywell

2004-1935 RFO-12 drywell valve maintenance

2004-1936 RFO-12 installation/removal of temporary shielding in the drywell

2004-1952 Perform walkdowns/take field measurements in drywell for permanent shielding design

2004-1953 RFO-12 ISI welds inside bioshield on N2 nozzels, including support activities

Procedures

RP-105	Radiation Work Permits, Revision 4
RP-108	Radiation Protection Postings, Revision 2
RP-204	Special Monitoring Requirements, Revision 3
RP-501	Respiratory Protection Program, Revision 0
RPP-0005	Management of Radiological Postings, Revision 25
RPP-0006	Performance of Radiological Surveys, Revision 18
RSP-0212	Drywell Entry, Revision 10A
ADM-0071	Fuel Pools Material Control, Revision 4

River Bend Condition Reports

CR-RBS-2003-1178
CR-RBS-2003-1205
CR-RBS-2003-1602
CR-RBS-2003-1716
CR-RBS-2003-1761
CR-RBS-2003-2416
CR-RBS-2003-2888
CR-RBS-2003-3255
CR-RBS-2003-3294
CR-RBS-2003-3304
CR-RBS-2003-3367
CR-RBS-2003-3371
CR-RBS-2003-3402
CR-RBS-2003-3475
CR-RBS-2003-3500
CR-RBS-2004-0641
CR-RBS-2004-0996
CR-RBS-2004-1249
CR-RBS-2004-1287
CR-RBS-2004-1974
CR-RBS-2004-1991
CR-RBS-2004-2318
CR-RBS-2004-2379
CR-RBS-2004-2472
CR-RBS-2004-2534
CR-RBS-2004-2759
CR-RBS-2004-3077
CR-RBS-2004-3325
CR-RBS-2004-3551

Self-Assessments/Audits

QS-2003-RBS-009
QS-2003-ENS-017
QS-2004-RBS-005

Miscellaneous

2003 Annual Radioactive Effluent Report

Section 4OA2: Identification and Resolution of Problems

Condition reports:

CR-RBS-2004-3795
CR-RBS-2004-3130
CR-RBS-2004-3201
CR-RBS-2004-3228
CR-RBS-2004-3231
CR-RBS-2004-3235
CR-RBS-2004-3294
CR-RBS-2004-3299
CR-RBS-2004-3400
CR-RBS-2004-3434
CR-RBS-2004-3485
CR-RBS-2004-3488
CR-RBS-2004-3492
CR-RBS-2004-3499
CR-RBS-2004-3518
CR-RBS-2004-3523
CR-RBS-2004-3546
CR-RBS-2004-3566
CR-RBS-2004-3580
CR-RBS-2004-3581
CR-RBS-2004-3588
CR-RBS-2004-3624
CR-RBS-2004-3730
CR-RBS-2004-3795
CR-RBS-2004-3797
CR-RBS-2004-3884
CR-RBS-2004-3932
CR-RBS-2004-3965
CR-RBS-2004-4031
CR-RBS-2004-4037
CR-RBS-2004-4065
CR-RBS-2004-4118

LIST OF ACRONYMS

ALARA	as low as is reasonably achievable
APRM	average power range monitor
ASME	American Society of Mechanical Engineers
BWR	boiling water reactor
BWRVIP	boiling water reactor vessel and internals project
CFR	*Code of Federal Regulations*
CR	condition report
CR-RBS	River Bend Station condition report
ECCS	emergency core cooling system
ESF	engineered safety features
HPCS	high pressure core spray
IAS	instrument air system
IMC	inspection manual chapter
LER	licensee event report
NCV	noncited violation
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
PI	performance indicators
RCIC	reactor core isolation cooling
RCS	reactor coolant system
RFO-12	Refueling Outage 12
RHR	residual heat removal
RSS	reserve station service transformer
SSC	structures, systems, or components
STP	surveillance test procedure
URI	unresolved item
USAR	Updated Safety Analysis Report
WO	work order