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

May 13, 2004

Paul D. Hinnenkamp
Vice President - Operations
Entergy Operations, Inc.
River Bend Station
5485 US Highway 61N
St. Francisville, LA 70775

SUBJECT: RIVER BEND STATION - NRC INTEGRATED INSPECTION REPORT 05000458/2004002

Dear Mr. Hinnenkamp:

On March 31, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your River Bend Station facility. The enclosed integrated inspection report documents the inspection findings, which were discussed on April 6, 2004, 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 two self-revealing and one NRC identified finding of very low safety significance (Green). These findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they were entered into your corrective action program, the NRC is treating these findings as noncited violations consistent with Section VI.A of the NRC Enforcement Policy. If you contest these noncited violations, 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, DC 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, DC 20555-0001; and the NRC Resident Inspector at the River Bend Station facility.

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 Website 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

Enclosure:
NRC Inspection Report 05000458/2004002
w/attachment: Supplemental Information

cc w/enclosure:
Senior Vice President and
Chief Operating Officer
Entergy Operations, Inc.
P.O. Box 31995
Jackson, MS 39286-1995

Vice President
Operations Support
Entergy Operations, Inc.
P.O. Box 31995
Jackson, MS 39286-1995

General Manager
Plant Operations
Entergy Operations, Inc.
River Bend Station
5485 US Highway 61N
St. Francisville, LA 70775

Director - Nuclear Safety
Entergy Operations, Inc.
River Bend Station
5485 US Highway 61N
St. Francisville, LA 70775

Wise, Carter, Child & Caraway
P.O. Box 651
Jackson, MS 39205

Mark J. Wetterhahn, Esq.
Winston & Strawn
1401 L Street, N.W.
Washington, DC 20005-3502

Manager - Licensing
Entergy Operations, Inc.
River Bend Station
5485 US Highway 61N
St. Francisville, LA 70775

The Honorable Charles C. Foti, Jr.
Attorney General
Department of Justice
State of Louisiana
P.O. Box 94005
Baton Rouge, LA 70804-9005

H. Anne Plettinger
3456 Villa Rose Drive
Baton Rouge, LA 70806

Burt Babers, President
West Feliciana Parish Police Jury
P.O. Box 1921
St. Francisville, LA 70775

Michael E. Henry, State Liaison Officer
Department of Environmental Quality
Permits Division
P.O. Box 4313
Baton Rouge, LA 70821-4313

Brian Almon
Public Utility Commission
William B. Travis Building
P.O. Box 13326
1701 North Congress Avenue
Austin, TX 78711-3326

Electronic distribution by RIV:
Regional Administrator **(BSM1)**
DRP Director **(ATH)**
DRS Director **(DDC)**
Senior Resident Inspector **(PJA)**
Branch Chief, DRP/B **(DNG)**
Senior Project Engineer, DRP/B **(RAK1)**
Staff Chief, DRP/TSS **(PHH)**
RITS Coordinator **(KEG)**
Rebecca Tadesse, OEDO RIV Coordinator **(RXT)**
RBS Site Secretary **(LGD)**

ADAMS: ✖Yes ☐ No Initials: __dng___
✖ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ✖ Non-Sensitive

R:_RB\2004\RB2004-02RP-PJA.wpd **ML041350047**

RIV:SRI:DRP/B	RI:DRP/B	C:DRS/PEB	C:DRS/EB	C:DRS/OB
PJAlter	MOMiller	LJSmith	CSMarschall	ATGody
E - DNGraves	***E - DNGraves***	***/RA/***	***JITapia for***	***GEWerner for***
5/11/04	5/11/04	5/12/04	5/11/04	5/12/04

C:DRS/PSB	C:DRP/B		
MPShannon	DNGraves		
/RA/	***/RA/***		
5/11/04	5/13/04		

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

<u>ENCLOSURE</u>

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	50-458
License:	NPF-47
Report:	05000458/2004002
Licensee:	Entergy Operations, Inc.
Facility:	River Bend Station
Location:	5485 U.S. Highway 61 St. Francisville, Louisiana
Dates:	January 1 through March 31, 2004
Inspectors:	P. J. Alter, Senior Resident Inspector, Project Branch B M. O. Miller, Resident Inspector, Project Branch B D. R. Carter, Health Physicist, Plant Support Branch B. K. Tharakan, Health Physicist, Plant Support Branch
Approved By:	D. N. Graves, Chief Project Branch B Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000458/2004002; January 1, 2004 - March 31, 2004; River Bend Station; ALARA Planning, Event Followup and Controls Identification and Resolution of Problems

The report covered a 3-month period of routine inspection by resident inspectors and an announced inspection by regional radiation protection inspectors. Three Green noncited violations (NCV), were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using 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: Mitigating Systems

- Green. The licensee failed to adequately address leaks in the roof of the auxiliary building following several instances when roof leaks were identified and documented in the licensee's corrective action program. On February 5, 2004, rainwater inleakage through the auxiliary building roof resulted in an electrical ground on the control circuits of auxiliary building 480 Vac engineered safety features Switchgear EJS-SWG2A. The finding was of very low safety significance because, although it degraded one train of safety-related equipment, and could have degraded it again, it did not: increase the likelihood of a primary or secondary system loss of coolant accident initiator, contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available, or increase the likelihood of a fire or internal/external flood.

  The inspectors determined that the failure to correct the leaks in the auxiliary building was a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action." Because this problem identification and resolution finding was of very low safety significance and was entered into the licensee's corrective action program as Condition Report CR-RBS-2004-01083, it is being treated as an noncited violation, consistent with Section VI.A of the NRC Enforcement Policy, NUREG-16000 (Section 4OA2).

Cornerstone: Barrier Integrity

- Green. The licensee operated the reactor plant at power levels above the licensed maximum power level from February 1996 to May 2003 due to an error in feedwater flow rate used to calculate reactor core thermal power. It was found that the feedwater flow rate data was inaccurate by as much as 2.69 percent rated system flow and actual thermal power was as much as 2.7 percent higher than the calculated thermal power. The inspectors determined that this finding was a problem identification and resolution finding because the licensee missed several opportunities to identify and correct this overpower condition.

  The finding was more than minor because if left uncorrected and a design basis accident occurred the resulting fuel damage could exceed analyzed values. The inspectors determined that the finding affected the reactor fuel cladding barrier, but was of very low safety significance because the reactor coolant system barrier was not effected. This self-revealing finding was a violation of operating license Condition 2.C.(1), “Maximum Power Level.” Because the violation was of very low safety significance and was entered in the licensee’s corrective action program as Condition Report CR-RBS-2003-02082, it is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy, NUREG-1600 (Section 4OA3).

Cornerstone: Occupational Radiation Safety

- Green. The inspectors identified a noncited violation of Technical Specification 5.4.1.a because the licensee failed to follow procedural requirements to verify the correct configuration and adequacy of permanent shielding. On March 25, 2004, the inspectors identified that permanent shielding on a low-pressure core spray flush line, in the crescent area of the 70-foot elevation of the auxiliary building, was not in the correct configuration and not adequate for the intended application.

  The failure to verify the correct configuration of permanent shielding and ensure that it was adequate for the intended application was a performance deficiency. The finding was greater than minor because it was associated with the Occupational Radiation Safety cornerstone attribute of Program and Process and effected the cornerstone objective to ensure the adequate protection of a worker’s health and safety from exposure to radiation. When processed through the Occupational Radiation Safety Significance Determination Process the finding was determined to be of very low safety significance because the finding was not associated with as low as is reasonably achievable issues, there was no overexposure or substantial potential for overexposure, and the ability to assess dose was not compromised. The finding was entered into the licensee's corrective action program as Condition Report CR-RBS-2004-00924 (Section 2OS2).

C. Licensee-Identified Findings

None.

REPORT DETAILS

Summary of Plant Status: The reactor was operated at 100 percent power from January 1-13, 2004, when power was reduced to 53 percent for a control rod pattern exchange. The reactor was operated at 100 percent power for the remainder of the inspection period, with the exception of routine reductions in reactor power for control rod exercising and turbine testing.

1. REACTOR SAFETY

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

1R04 Equipment Alignments (71111.04)

a. Inspection Scope

The inspectors performed three partial system walkdowns during this inspection period. On January 21, 2004, the inspectors walked down residual heat removal (RHR) Train B while RHR Train A was out of service for planned maintenance. On March 10, 2004, the inspectors walked down the high pressure core spray (HPCS) while reactor core isolation cooling (RCIC) was out of service for planned maintenance. On March 12, 2004, the inspectors walked down RCIC following the return to service from unplanned maintenance. In each case, the inspectors verified the correct valve and power alignments by comparing positions of valves, switches, and electrical power breakers to the procedures and drawings listed below and applicable sections of the Updated Safety Analysis Report (USAR).

- SOP-0031, “Residual Heat Removal,” Revision 41
- PID-27-07B, “Residual Heat Removal System,” Revision 39
- SOP-0030, “High Pressure Core Spray,” Revision 20
- PID-27-04A, “High Pressure Core Spray System,” Revision 24
- SOP-0035, “Reactor Core Isolation Cooling,” Revision 21
- PID-27-06A, “Reactor Core Isolation Cooling System,” Revision 40

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors walked down accessible portions of seven 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 penetration; and (5) any related compensatory measures. The areas inspected were:

- Auxiliary Building, 70-foot elevation, Division III Emergency Core Cooling System (ECCS) pump room area, fire Zone AB-2/Z-1, on January 9, 2004

- Auxiliary building, 141-foot elevation east mezzanine, Division II safety-related 480 volt motor control center room area, fire Zone AB-15/Z-4, on January 12, 2004

- Auxiliary building, 70-foot elevation, RHR Train B room, fire Zone AB-3, on January 21, 2004

- Auxiliary building, 170-foot elevation, annulus mixing fan area, fire Zone AB-16, on February 13, 2004

- Auxiliary building, 95-foot elevation, RCIC and RHR Train C access area, fire Area AB-4/Z-2, on February 19, 2004

- Auxiliary Building, 114-foot elevation - east, Division II low pressure ECCS room Cooler 1HVR-UC9 area, fire Zone AB-15/Z-3, on February 25, 2004

- Auxiliary Building, 114-foot elevation - west, Division I low pressure ECCS and RCIC room Cooler 1HVR-UC6 area, fire Zone AB-1/Z-3, on February 25, 2004

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

- Pre-Fire Strategy Book

- USAR Section 9A.2, "Fire Hazards Analysis"

- River Bend postfire safe shutdown analysis

- RBNP-038, "Site Fire Protection Program," Revision 6A

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors looked at the effect on the internal flooding analysis for RHR Train B room, as a result of the failed open drain valve in the standby service water crossconnect line to RHR Train B, as documented in Condition Report (CR-RBS) CR-RBS-2004-0364. Of particular concern was the effect that the use of this crossconnect would have on further actions taken by the operators during implementation of emergency operating procedures (EOP), specifically Procedure EOP-4, Sheet 4, "Reactor Pressure Vessel (RPV) Flooding," Revision 8. The inspectors conducted a walkdown of the RHR Train B room on February 20, 2004. Specifically, the inspectors examined: (1) sealing surfaces of watertight doors, (2) sealing of equipment below design flood level, (3) sealing of penetrations in floors and walls, (4) interconnections with common drain systems for possible spread of the flooding to other emergency equipment rooms. In addition, the inspectors reviewed the effect the anticipated volume of water, that would flood the room when the standby service water crossconnect was used, would have on the use of RHR Train B equipment after implementation of Procedure EOP-5, “Emergency Operating and Severe Accident Procedures Enclosures,” Enclosure 22, “RPV Injection/Containment Flooding with Service Water,” Revision 15.

- River Bend individual plant examination of external events
- USAR Section 3.4.1, “Flood Protection”
- G13.18.12.3*15, “Internal Flooding Screening Analysis”
- G13.2.3 PN-317, “Max Flood Elevations for Moderate Energy Line Cracks in Cat I Structures”

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors reviewed the expected performance of the Division II diesel generator jacket cooling water heat exchanger that transfers heat to the standby service water system. This review was conducted by reviewing documents and by interviewing licensee staff. The inspectors verified that: (1) differences between testing conditions and design conditions were appropriately considered, (2) heat exchanger tests/inspection results were appropriately categorized against pre-established engineered acceptance criteria and were acceptable, (3) the number of tubes plugged didn’t effect the heath exchanger’s operability, and (4) tests did consider test instrument inaccuracies and differences. The inspectors evaluated their observations against the requirements of the following documents:

- USAR Table 9.5-6, “Standby Diesel Generator Cooling Water System Components”
- Procedure PEP-0246, Revision 0, “Division II Standby Diesel Generator Jacket Water Cooler Data and Performance Evaluation”

b. Findings

No findings of significance were identified

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

On February 24, 2004, the inspectors observed simulator training of an operating crew as part of the operator requalification training program to assess licensed operator performance and the training evaluator's critique. Emphasis was placed on observing weekly training exercises of high risk, licensed operator response, lessons learned from industry, and plant experiences. Crew performance was compared to licensee management expectations and guidelines as presented in Administrative Procedure ADM-22, "Conduct of Operations," Revision 30. For identified weaknesses, the inspectors observed the licensee evaluators to determine if they also noted the issues and discussed them in the critique at the end of the session. In addition, the inspectors compared simulator control panel configurations with the actual control room panels for consistency. The simulator training scenario observed was RSMS-OPS-515, "Inadvertent closure of MSIV," Revision 0.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12)

a. Inspection Scope

In order to assess the effectiveness of the licensee's maintenance efforts for structures, systems, and components (SSC) within the scope of the maintenance rule program, the inspectors reviewed: (1) main turbine control system problems which resulted in a plant trip during control valve testing; and (2) the auxiliary building performance problem resulting from a roof leak during heavy rains. The inspectors verified the licensee's maintenance effectiveness by: (a) verifying the licensee's handling of SSC performance or condition problems, (b) verifying the licensee's handling of degraded SSC functional performance or condition, (c) evaluating the role of work practices and common cause problems, and (d) 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-2003-3203, plant trip during control valve testing on September 22, 2003

- CR-RBS-2004-00352, auxiliary building roof leak and CR-RBS-2004-00346, auxiliary building roof leak causes ground

- NUMARC 93-01, Revision 2, Nuclear Energy Institute Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants

- Maintenance rule database (function list, performance criteria list, functional failure evaluations)

- Procedure EDG-CS-003, “Maintenance Rule Structural Monitoring at River Bend Station,” Revision 0

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed seven 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.

.1 Risk Assessment and Management of Risk

On a routine basis, the inspectors verified performance of risk assessments, in accordance with Administrative Procedure ADM-096, “Risk Management Program Implementation and On-Line Maintenance Risk Assessment,” Revision 04, for planned maintenance activities and emergent work involving SSC within the scope of the maintenance rule. Specific work activities evaluated included planned and emergent work for:

- the week of January 11, 2004, during a planned downpower for planned maintenance and a control rod pattern exchange

- the week of January 19, 2004, during planned work activities during a Division I engineered safety system outage

.2 Emergent Work Control

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

- Division I emergency diesel generator shuttle valve malfunctioned during postmaintenance testing, which extended planned maintenance outage duration on January 21, 2004

- Instrument ac power line conditioning Transformer SCI-XRC10B1 control failure on January 22, 2004
- Failure of service water bypass line piping drain Valve E12-SOVF095 and potential for RHR Train B flooding on February 22, 2004
- Main generator automatic voltage regulator problems requiring shift to manual voltage control from March 2-25, 2004
- RCIC inoperable due to suppression pool suction Valve E51-MOVF031 control circuit malfunction on March 11, 2004

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions and Events (71111.14)

.1 Entry into Emergency Procedure EOP-3, “Secondary Containment Control”

The inspectors reviewed and observed operations personnel performance following “Reactor Water Equipment Room High Differential Temperature” annunciator alarm on January 29, 2004. The alarm requires entry into Procedure EOP-3, “Secondary Containment Control.” The inspectors evaluated the initiating causes of the event by interviewing control room crew personnel, evaluating control room indications, and inspecting the area using a remote-control camera within 15 minutes of the event. In addition, the inspectors evaluated the control room team’s response to the event by reviewing marked up emergency operating procedures, abnormal operating procedures, alarm response procedures, operator logs, and plant computer data to determine what occurred and that operators responded in accordance with plant procedures and training. The inspectors also interviewed the emergency planning manager regarding the appropriate event classification for this steam leak in the auxiliary building. This condition had existed since August 28, 2003, was placed in the licensee’s corrective action program as CR-RBS-2003-3029, and was noted as increasing in severity on December 19, 2003, in CR-RBS-2003-3802. The inspectors reviewed the following procedures used by the operators during the event:

- Alarm response Procedure 2408, “RWCU EQUIP RMS Differential High Temps,” Revision 11
- Emergency Operating Procedure EOP-003, “Secondary Containment and Radioactive Release Control,” Revision 13
- Emergency Implementing Procedures EIP-2-001, “Classification of Emergencies,” Revision 12

.2 January 22, 2004, Control Rod Pattern Exchange

The inspectors observed reactor engineering and operations personnel performance during the January 13, 2004, power reduction for a control rod sequence exchange During the inspection, the inspectors reviewed the work plan for the downpower and control rod sequence exchange and observed the interaction between two reactor engineers and the control room operators and the various pre-evolution briefs given in the control room by the control room supervisor. The inspectors also reviewed "Reactivity Control Plan 12-024," issued December 18, 2003, used during the downpower to 53 percent power and subsequent return to full power operations.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed six operability determinations selected on the basis of risk insights. The selected samples were addressed in the documents 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 review included a verification that the operability determinations were made as specified by Procedure RBNP-078, "Operability Determinations," Revision 07. The operability evaluations reviewed were associated with:

- CR-RBS-2004-00085, Division I main steam positive leakage control system drain valve control Relay E33A-K9A, replacement and subsequent operability determination, reviewed on January 16, 2004

- ER-99-0769, Division I standby service water returned to service after replacing snubbers with rigid supports, reviewed on January 22, 2004

- CR-RBS-2004-00286, issue raised by Grand Gulf Nuclear Station (CR-GGN-2004-00318), regarding post-LOCA containment leakage via RCIC turbine exhaust line, reviewed on February 2, 2004

- CR-RBS-2004-0346, auxiliary building roof leak redirected away from auxiliary building 480 VAC engineered safety features Switchgear EJS-SWGR2A using plastic sheeting, reviewed February 11, 2004

- Surveillance Test Procedure STP-000-6606, "Section XI Safety and Relief Valve Testing," Revision 14,RCIC lube oil cooler water supply line relief Valve E51-PCVF015, reviewed on March 8, 2004.

- CR-RBS-2004-0164, control building air conditioning Chiller HVK-CHL1A inoperable during troubleshooting, reviewed on March 25, 2004

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (IP 71111.16)

a. Inspection Scope

The inspectors reviewed the effect of two operator workarounds on the operation of the plant. 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 January 14, 2004, the inspectors reviewed the manual override of service water outlet/bypass Valve SWP-PVY32B for control building air conditioning Chiller HVK-CHL1B. On February 24, 2004, the inspectors reviewed the loss of nuclear instrumentation after a reactor scram caused by a loss of off-site power. The inspectors looked at: (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. The procedures reviewed by the inspectors during this inspection were

- SOP-0066, “Control Building HVAC Chilled Water System,” Revision 30
- STP-000-0001, “Daily Operating Logs,” Data Sheet 1, Revision 43.
- AOP-0004, “Loss of Off Site Power,” Revision 25
- AOP-0010, “Loss of One [Reactor Protection System] Bus,” Revision 13

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors selected one permanent plant modification completed on standby service water system and low pressure core spray system pump suction piping supports. The modification replaced snubbers with rigid support struts. The modification, documented in ER-99-0769, involved 10 work order packages as shown in the list of documents reviewed section of this report. The inspectors verified that modification preparation, staging, and implementation did not impair emergency or abnormal procedure actions, key safety functions, or operator response to the loss of key safety functions. The inspectors also verified that postmodification testing maintained the plant in a safe configuration. The licensee’s operability declaration was confirmed by: verifying that unintended system interactions did not occur; verifying SSC performance characteristics met the design basis; validating the appropriateness of modification design assumptions; and demonstrating that the modification test acceptance criteria were met.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed nine work orders (WO) and maintenance action items (MAI) to ensure that testing activities were adequate to verify system operability and functional capability. The inspectors: (1) identified the safety functions for each system by reviewing applicable licensing basis and/or design-basis documents; (2) reviewed each maintenance activity to identify which maintenance functions may have been effected; (3) reviewed each test procedure to verify that the procedure did adequately test the safety function(s) that may have been effected 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 WOs and MAIs inspected are listed below:

- WO 50372617, Division II diesel postoutage inspection, reviewed on January 14, 2003

- WO 50372617, Main steam positive leakage control drain valve control Relay E33A-K9A replacement, reviewed on January 14, 2004

- WO 50688493, Functional test Division I emergency start and normal start valves, reviewed on February 2, 2004

- WO 00033834, Division I diesel jacket water pump discharge pressure switch replacement, reviewed on February 2, 2004

- WO 50688464, Division I diesel overspeed fast trip regulator, stop/run valve, bar lockout valve, overspeed valve, overspeed manual reset valve, stop/run timer testing, reviewed on February 2, 2004

- WO 50658183, Division I diesel stop/run valve timer replacement, reviewed on February 2, 2004

- WO 50371774, Replacement of the damaged stem and disk of the Division I standby service water test return isolation valve, reviewed on February 12, 2004.

- MAI 336293, RCIC lube oil cooler cooling water supply line relief Valve E51-RVF018 ASME test, reviewed on February 23, 2004.

- MAI 336357, RCIC lube oil cooler cooling water supply line relief Valve E51-RVF018 postoverhaul ASME test, February 24, 2004.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

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

- STP-052-3701, “Control Rod Scram Testing,” Revision 20, performed April 10, 2003
- STP-610-3829, “Reactor Plant Sampling Penetration KJB-Z601F Valve Leak Rate Test,” Revision 1, performed February 13, 2004
- STP-309-0203, “Division III Diesel Generator Operability Test,” Revision 25, performed February 25, 2004
- STP-209-6310, “RCIC Quarterly Pump and Valve Operability Test,” Revision 23, performed March 12, 2004
- STP-209-6601, “RCIC Eighteen Month Position Indication Verification Test,” Revision 1, performed March 11, 2004

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

During the week of January 19, 2004, the inspectors reviewed the temporary plant modification made to monitor performance of control building air conditioning Chiller HVK-CHL1A that was installed in engineered safety features load Center EJS-SWG1A and motor control Center EHS-MCC8A. 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; and (2) verified that the installation of the temporary modification was consistent with the modification documents to confirm the actual impact of the temporary modification on the effected system and the electrical switchgear had been adequately verified.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed an emergency preparedness drill conducted on March 2, 2004, 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 drill 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
- Site drill manual, Scenario RDRL-EP-030, Revision 01

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS2 As Low as is Reasonably Achievable (ALARA) Planning and Controls (71121.02)

a. Inspection Scope

The inspectors assessed licensee performance with respect to maintaining individual and collective radiation exposures ALARA. The inspectors used the requirements in 10 CFR Part 20 and the licensee's procedures required by Technical Specification 5.4.1 as criteria for determining compliance. The inspectors interviewed licensee personnel and reviewed:

- Current 3-year rolling average collective exposure

- Site-specific trends in collective exposures, plant historical data, and source-term measurements

- Site specific ALARA procedures

- Shielding requests and dose/benefit analysis
- Exposures of individuals from chemistry, maintenance, and security work groups
- Records detailing the historical trends and current status of tracked plant source terms and contingency plans for expected changes in the source term due to changes in plant fuel performance or changes in plant primary chemistry
- Source-term control strategy or justifications for not pursuing such exposure reduction initiatives
- Three declared pregnant workers during the current assessment period, monitoring controls, and the exposure results
- Self-assessments, audits, and special reports related to the ALARA program since the last inspection
- Corrective action documents related to the ALARA program and followup activities, such as initial problem identification, characterization, and tracking
- Effectiveness of self-assessment activities with respect to identifying and addressing repetitive deficiencies or significant individual deficiencies

The inspectors completed 7 of the required 15 samples and 4 of the optional samples.

b. Findings

Introduction. The inspectors identified a Green, noncited violation (NCV) of Technical Specification 5.4.1.a because the licensee failed to follow procedural requirements to verify the correct configuration and adequacy of permanent shielding.

Description. On March 23, 2004, during a tour of the crescent area on the 70-foot elevation of the auxiliary building, the inspectors identified a gap in permanent shielding installed on a low pressure core spray flush line. The inspectors reviewed Procedure ADM-0046, “Shielding Control Program,” Revision 05, and determined that the licensee established quarterly inspection requirements for shielding installations to verify the correct configuration and ensure that the shielding remained adequate for the intended application. During interviews, the inspectors determined that the licensee had inspected the condition of the shielding; however, the licensee failed to verify the correct configuration and adequacy of the shielding. The shielding was installed on the flush line to reduce radiation exposure. The radiation exposure from the gap in the shielding was as high as 25 millirem per hour at 30 cm and exceeded the general area dose rates in the room. Therefore, the inspectors determined that the licensee did not perform the actions required by the procedure.

Analysis. The failure to verify the correct configuration and adequacy of permanent shielding was a performance deficiency. This finding was greater than minor because it effected the Occupational Radiation Safety cornerstone objective to ensure adequate protection of a worker's health and safety from exposure to radiation and is associated with the cornerstone attribute of Program and Process. When the finding was processed through the Occupational Radiation Safety Significance Determination Process, the inspectors determined the finding to be of very low safety significance because it was not associated with ALARA planning or work controls, there was no overexposure or substantial potential for an overexposure, and the ability to assess dose was not compromised.

Enforcement. Technical Specification 5.4.1.a requires that written procedures be established, implemented, and maintained covering the applicable procedures referenced in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Appendix A, Section 7, references procedures for control of radioactivity and limiting personnel exposure. Procedure ADM-0046, step 6.8.2, required that, on a quarterly basis, all accessible shielding installations be inspected to include verification that the shielding was in the correct configuration and was still adequate for the intended application. On March 25, 2004, the inspectors determined that permanent shielding was not verified to be in the correct configuration nor adequate for the intended application. Because the failure to verify the correct configuration and adequacy of permanent shielding was of very low safety significance and was entered into the corrective action program as CR-RBS-2004-00924, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000458/2004002-01).

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

The inspectors sampled licensee submittals for the three performance indicators (PI) listed below for the period from January 1 through December 31, 2003. To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in NEI (Nuclear Energy Institute) 99-02, "Regulatory Assessment Indicator Guideline," Revision 2, were used to verify the basis in reporting for each data element.

Initiating Event Cornerstone

- Unplanned reactor scrams per 7,000 critical hours
- Scrams with a loss of normal heat removal per 12 quarters
- Unplanned power changes per 7,000 critical hours

The inspectors sampled portions of operator logs, monthly operating reports, and PI data sheets to determine whether the licensee adequately identified the number of scrams and unplanned power changes greater than 20 percent that occurred during the previous four quarters. This number was compared to the number reported for the PI during the current quarter. The inspectors also verified the accuracy of the number of critical hours reported and the licensee's basis for crediting normal heat removal capability for each of the reported reactor scrams. In addition, the inspectors also interviewed licensee personnel associated with the PI data collection, evaluation, and distribution.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Cross-Reference to Problem Identification and Resolution Findings Documented Elsewhere

Section 2OS2 evaluated the effectiveness of the licensee's problem identification and resolution processes regarding exposure tracking, higher than planned exposure levels, and radiation worker practices. No findings of significance were identified.

Section 40A3 describes a self-revealing finding related to operating the reactor plant at power levels in excess of the maximum power level license limit. The inspectors determined that inaccurate correction factors were applied to the feedwater venturi flow instrument outputs and then used in the reactor thermal heat balance calculation. The results of the heat balance calculations were then used to determine reactor core thermal power. As a result, the reactor core was operated in excess of the maximum power level license limit, even though the licensee had several opportunities to identify and correct the problem

.2 Periodic review of the licensee's ability to identify and resolve problems: repetitive leakage through the roof of the auxiliary building

a. Inspection Scope

The inspectors selected an issue (roof leak in the auxiliary building roof) during this inspection period for a more in-depth, periodic review of the licensee's ability to identify and resolve problems. This selected issue was a self-revealing issue noted by the inspectors during a routine plant tour. Attributes evaluated during the inspectors' review of the licensee's actions associated with this issue 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 noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," based on the licensee's failure to adequately address leaks in the roof of the auxiliary building following several instances when leaks were identified and documented in the licensee's corrective action program. The finding was of very low safety significance (Green) because the auxiliary building roof leak did not increase the likelihood of a plant trip or degrade more than one train of any safety system.

Description. On February 5, 2004, during a heavy rainstorm, an alarm was received in the main control room for a ground on control building 125 Vdc engineered safety features load Switchgear ENB-SWG1A, which provides control power to other engineered safety features electrical switchgear. The operators contacted electrical maintenance technicians who determined the ground was on auxiliary building 480 Vac engineered safety features Switchgear EJS-SWGR2A. The inspectors interviewed the electrical maintenance supervisor who stated that he quickly identified the source of the ground on ENB-SWG1A as control power for EJS-SWGR2A based on a similar occurrence on March 12, 2003. After observing the ground detector indicators on ENB-SWG1A in the control building, he went straight to EJS-SWGR2A in the auxiliary building. When he arrived there, he found a roof leak, similar to the one that caused the March 12, 2003, ground, dripping rainwater onto EJS-AWGR2A. The operators protected EJS-SWGR2A with plastic sheets to deflect the rainwater into buckets and set out a portable fan to cool and dry out the switchgear under the plastic sheeting. The ground subsequently dried out and the control room alarm reset.

Electrical maintenance technicians performed a preliminary visual inspection of the controls cabinets in Switchgear EJS-SWGR-2A and plan to conduct a more detailed inspection during the next refueling outage. CR-RBS-2004-00346 was written to document the ground and track corrective actions to resolve the residual electrical problems within the switchgear. CR-RBS-2004-0352 was written to resolve the problem with the leakage of rainwater onto EJS-SWGR2A and into the standby gas treatment Train B room.

The inspectors conducted a historical search of the licensee's corrective action program and found that nine condition reports and two MAIs had been written for auxiliary building roof leaks since 2002. Rainwater had also leaked through the auxiliary building roof into the standby gas treatment system rooms and other open areas of auxiliary building Elevation 141, as well as onto Switchgear EJS-SWGR2A. Important details of that search included:

- On October 28, 2002, CR-RBS-2002-01675 was written documenting auxiliary building roof leaks that needed to be inspected and resealed. MAI 365266 was generated to seal the equipment removal plugs in the auxiliary building roof. The condition report was closed to the MAI.

- On April 5, 2003, CR-RBS-2003-01654 was written documenting an auxiliary building roof leak that caused a ground on EJS-SWG2A and leaked into the standby gas treatment Train A room. The condition report was also closed to MAI 365266.

- On June 17, 2003, MAI 365266 was signed off as complete.

- On February 5, 2004, CR-RBS-2004-353 was written documenting the continued inleakage of rainwater through the auxiliary building roof and the closure of the two condition reports listed above to MAI 365266 without solving the problem of the roof leak.

- On March 12, 2003, CR-RBS-2003-00908 was written documenting a ground fault on ENB-SWG1A. The ground was found to be in the control circuit for hydrogen Recombiner HCS-RBNR1 on EJS-SWGR2A. The cause of the ground was water intrusion into the breaker cubicle from a leak in the auxiliary building roof. The condition report was closed after replacement of the breaker. No corrective actions were documented to resolve the problem with the rainwater intrusion into the switchgear.

- On March 31, 2003, CR-RBS-2003-01550 was written documenting a trip of the normal feeder breaker to the containment polar crane in EJS-SWGR2A. This breaker provided electrical circuit protection for the containment cable penetration feeding the polar crane. During the troubleshooting of this breaker, the licensee found evidence of water damage to breaker internal components. The condition report was closed upon replacement of the breaker. No action was taken to resolve the problem with the water intrusion into the breaker cubicle.

- On February 15, 2004, the licensee wrote CR-RBS-2004-00479 to document an auxiliary building roof leak. This time rainwater was coming from the auxiliary building/reactor building interface. On February 17, 2004, CR-RBS-2004-00479 was closed to CR-RBS-2004-00346, which addressed the February 5, 2004, auxiliary building roof leak.

On December 13, 2003, the inspectors found that the auxiliary building roof was leaking while a rainstorm was in progress. The inspectors notified the shift manager and the work control center. The licensee did not take actions to document the leak in the licensee's corrective action program and did not conduct any followup actions beyond placing a "wet floor" sign in the area.

On February 6, 2004, the licensee conducted a search of the corrective action program and found an additional eight condition reports and five MAIs documenting radwaste building roof leaks into the auxiliary control room radioactive waste treatment panels.

In summary, the auxiliary building roof leaks have resulted in the failure or degradation of the following equipment: (1) ground faults on Division I safety-related 480 volt load Center EJS-LDC2A on three separate occasions in January 1995, March 2003, and February 2004; (2) ground fault on Switchgear ENB-SWG1A in March 2003; (3) grounds on Switchgear EJS-SWG2A in February 2004; (4) rust formation inside the breaker for the polar crane in EJS-SWG2A in January 2003; (5) trip of the breaker for the polar crane in April 2003; (6) Division I hydrogen recombiner circuit breaker replacement in April 2003; (7) tripped undervoltage/ground trip relay on EJS-SWG1A in June and July

2003; (8) water on radwaste control panels in the auxiliary control room documented several times back to 1995; and (9) auxiliary building/reactor building seal leakage in February 2004.

Analysis. The inspectors determined that the failure to take effective corrective actions to stop the auxiliary building roof leakage was a performance deficiency. The inspectors determined that this performance deficiency led directly to the malfunction of safety-related equipment inside the auxiliary building. 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. This self-revealing finding was more than minor because, if left uncorrected, the auxiliary building roof leak could lead to the loss of function of safety-related equipment. 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 (Green) because the auxiliary building roof leak did not increase the likelihood of a plant trip or degrade more than one train of any safety system.

Enforcement. The inspectors determined that the failure to correct the leaks in the auxiliary building was a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action." Because this problem identification and resolution finding was of very low safety significance and was entered into the licensee's corrective action program as CR-RBS-2004-01083, it is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy, NUREG-16000 (NCV 05000458/2004002-02).

4OA3 Event Followup (71153)

(Closed) Licensee Event Report (LER) 05000458/2003-005-01, Operation greater than maximum licensed power due to erroneous feedwater flow measurement

a. Inspection Scope

The inspectors reviewed the subject LER and the licensee's analysis of the event as documented in CR-RBS-2003-02082. 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 leading edge flow meter (LEFM) problems, (3) the licensee's determination of extent of condition, and (4) the appropriateness of corrective actions taken and planned. In addition, the inspectors interviewed operations personnel and engineering personnel responsible for monitoring LEFM performance.

b. Findings

Introduction. The licensee operated the reactor plant at power levels above the licensed maximum power level from February 1996 to May 2003 due to an error in feedwater flow rate data used to calculate reactor core thermal power. It was found that the feedwater flow rate data was inaccurate by as much as 2.69 percent rated system flow, and actual thermal power was as much as 2.7 percent higher than the calculated thermal power.

Description. On February 27, 1996, the licensee began using external LEFMs to manually correct feedwater flow data in the plant process computer. By reducing conservatism in feedwater flow measurements caused by feedwater flow venturi fouling, the licensee was able to operate the reactor plant at a higher reactor core power level. The first correction was made on February 27, 1996. As a result, the licensee increased core thermal power approximately 1.5 percent. Correction factors were recalculated monthly and again each time the plant was shut down. Periodic corrections were made to the feedwater flow venturi output to the process computer when the difference between the external LEFMs and the venturi meters reached a predetermined limit.

On May 10, 2003, the licensee received a vendor report for the new upgraded LEFM installed during the previous refueling outage (RFO). Based on the results of that report, the licensee determined that the external LEFM was not accurate. As a result, correction factors that were applied to the feedwater flow venturi outputs were nonconservative, making measured reactor feedwater flow less than actual flow. The plant process computer using feedwater flow rate data that was less than actual flow calculated an erroneously low reactor core thermal power. Using this nonconservative data, the licensee increased reactor power and operated the reactor core in excess of licensed maximum power level.

The licensee conducted an analysis of past operating data for the time the external LEFM was in service from February 27, 1996, to May 10, 2003. The analysis was based on other plant parameters not normally used in the reactor heat balance. They determined that the reactor was operated in excess of 102 percent licensed maximum power level for approximately 15 months. A licensed maximum power level of 102 percent was used as a basis for the USAR transient and accident analysis. Detailed results of the overpower analysis included:

- Licensed maximum power level was exceeded continuously from February 27, 1996, until the time of the high pressure turbine rotor replacement in 1999.

- Licensed maximum power level was exceeded almost continuously from the time of the high pressure turbine rotor replacement until a 5 percent power uprate in October 2000.

- Reactor core thermal power continuously exceeded 102.5 percent licensed maximum power level from October 2000 until April 2001.

- Reactor core thermal power exceeded 102 percent of the licensed maximum power level from April 2001 until RFO-10 in October 2001.

- Following RFO-10, 102 percent licensed maximum power level was exceeded again from January until May 2002, at which time thermal power was below 102 but above 100 percent licensed maximum power level. Power remained above the licensed maximum power level until coastdown to RFO-11 in January 2003.

The licensee identified two root causes for exceeding the licensed maximum power level: (1) no criteria existed to ensure that the external LEFM correction factors were reasonable compared to other power dependent plant parameters, and (2) no criteria existed to verify core thermal power was reasonable compared to other power dependent plant parameters.

The licensee identified these three contributory causes for the errors in the external LEFM: (1) changes in velocity profiles beyond the leading edge flow meter's calibration assumptions, (2) change in the effective location of the acoustic path such that its new position was outside the design range, and (3) an error in the measurement of the outside diameter of feedwater Line B.

The licensee conducted an evaluation of fuel cladding integrity, reactor vessel integrity, containment integrity and postaccident radiological consequences for this extended overpower condition. Transient and accident analyses used as part of the licensing basis typically assumed 102 percent licensed maximum power level as an initial condition. The evaluation for exceeding the licensed maximum power level addressed the impact of an additional 0.7 percent in thermal power (102.7 percent). The results were:

- The margin to the operating limits for fuel cladding integrity was sufficient to accommodate the 0.7 percent overpower.
- Reactor vessel and containment integrity was not challenged during the period in which the external LEFM correction factors were in use.
- A review of the calculations for power accident radiological dose consequences indicated that there was enough margin to the acceptance criteria to accommodate the overpower.
- There were no negative effects on other plant equipment not previously evaluated in their safety significance evaluation.

The inspectors reviewed the licensee's corrective actions to prevent recurrence including: (1) the external LEFM were removed from service, (2) the process computer can now display "best statistical estimate of core thermal power" based on 18 independent power dependent parameters; (3) the process computer can now display the percent difference between this estimate and calculated core thermal power; (4) training was conducted to communicate lessons learned and raise awareness regarding plant design changes and small changes in plant process parameters; and (4) the licensee evaluated other plant equipment for single indication vulnerability.

The inspectors determined that the licensee missed several opportunities to identify and resolve this overpower condition from the time they began applying correction factors to the feedwater flow venturi instrument outputs. These opportunities are documented in condition reports that identified problems with the external LEFM, condition reports from two other Entergy plants that identified problems with external LEFMs, and industry operating experience reports from five plants outside the Entergy system that identified problems with similar LEFM systems.

Analysis. The inspectors determined that the licensee's performance deficiency was the failure to properly calibrate the external LEFM. The inspectors determined that this performance deficiency led directly to operating the plant above its licensed maximum power level. The inspectors determined that this finding contained problem identification and resolution aspects because the licensee missed several opportunities to identify and correct this overpower condition. The inspectors reviewed the finding using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." The finding was more than minor because if left uncorrected and a design basis accident occurred the resulting fuel damage could exceed analyzed values. The inspectors determined that the finding affected the reactor fuel cladding barrier, but was of very low safety significance (Green) because the reactor coolant system barrier was not affected.

Enforcement. This self-revealing finding was a violation of operating license Condition 2.C.(1), "Maximum Power Level." The failure to comply with license Condition 2.C.(1) by exceeding licensed maximum power level from February 26, 1996, until May 10, 2003, as documented in LER 2003-005-01, was of very low safety significance because the finding did not also affect the reactor coolant system barrier. Because this problem identification and resolution finding was of very low safety significance and was entered in the licensee's corrective action program as CR-RBS-2003-02082, it is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy, NUREG-1600 (NCV 05000458/2004002-03).

4OA6 Management Meetings

Exit Meetings

The health physics inspectors presented the ALARA inspection results to Paul D. Hinnenkamp, Vice President - Operations, River Bend Station, and other members of licensee management at the conclusion of the inspection on March 25, 2004.

The inspectors presented the inspection results to Paul D. Hinnenkamp, Vice President - Operations, River Bend Station, and other members of licensee management at the conclusion of the inspection on April 6, 2004.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

M. Boyle, Superintendent, Radiation Protection
D. Burnett, Superintendent, Chemistry
S. Belcher, Acting Operations Manager
C. Forpahl, Manager, Corrective Action and Assessment
J. Fowler, Manager, Quality Programs
A. James, Superintendent, Plant Security
T. Gates, Manager, System Engineering
H. Goodman, Manager, Nuclear Engineering
R. Goodwin, Manager, Training and Development
J. Heckenberger, Manager, Planning and Scheduling/Outage
P. Hinnenkamp, Vice President - Operations
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 and Closed

05000458/2004002-01	NCV	Failure to verify the correct configuration and adequacy of permanent shielding
05000458/2004002-02	NCV	Failure to adequately address roof leaks in the auxiliary building resulted in electrical grounds on safety-related switchgear
05000458/2004002-03	NCV	Reactor operated in excess of licensed maximum power level due to erroneous feedwater flow measurement

Closed

05000458/2003-005-01	LER	Operation greater than maximum licensed power due to erroneous feedwater flow measurement

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 1R04 Equipment Alignments (71111.04)

CR-RBS-2003-02256, three condition reports have been initiated documenting unsatisfactory relay calibrations in HPCS, initiated May 29, 2003

CR-RBS-2003-02621, during Division III ECCS test, numerous trip unit gross fail alarms were received when the high pressure core spray pump was started, initiated July 9, 2003

CR-RBS-2003-02732, NRC performance indicator for HPCS unavailability value is more than half the value needed to turn the indicator white, initiated July 22, 2003

CR-RBS-2003-02937, grid transient caused by lightening strike alarmed annunciators in the control room, initiated August 16, 2003

CR-RBS-2003-03134, found HPCS room floor drain Pump DFR-P2M control switch in the "OFF" position, initiated September 14, 2003

CR-RBS-2003-03185, HPCS pump breaker had to be racked out due to a low pressure condition while performing maintenance on the line fill pump, initiated September 19, 2003

Section 1R17 Permanent Plant Modifications (71111.17)

WOP 50361567, replace Snubber SWP-PSSP-1201 (G-tunnel 69' el, 28' west of tee/SWP-MOV55A) on Division I standby service water system with Strut SWP-PSST-1201

WOP 50359371, replace Snubber SWP-PSSP-1445 (D-tunnel 83' el, 1' downstream SWP-V199) on Division I standby service water system with Strut SWP-PSST-1445.

WOP 50361569, replace Snubber SWP-PSSP-1435 (G-tunnel, 78' el) on Division I standby service water system with Strut SWP-PSSTP-1435

WOP 50361568, replace Snubber SWP-PSSP-1617 (G-tunnel, 78' el) on Division I standby service water system with Strut SWP-PSST-1617

WOP 50361566, replace Snubber SWP-PSSP-1443 (G-tunnel, 69' el) on Division I standby service water system with Strut SWP-PSST-1443

WOP 50361571, replace Snubber SWP-PSSP-1098 (B-tunnel, 72' el) on Division I standby service water system return line with Strut SWP-PSST-1098

WOP 50359366, replace Snubber SWP-PSSP-1064 (B-tunnel, 70' el) on Division I standby service water system supply line with Strut SWP-PSST-1064

WOP 50359370, replace Snubber SWP-PSSP-1194 (D-tunnel, 78' el., 3' downstream of E12-MOVF068A service water from RHR A heat exchanger) on Division I standby service water line with Strut SWP-PSST-1194

WOP 50361570, replace Snubber SWP-PSSP-1094 (B-tunnel, 71' el, connects to a dead leg) on Division I standby service water line with Strut SWP-PSST-1094

WOP 50329347, replace Snubber CSL-PSSP-2009 (auxiliary building, 73' el, 8' north of CSL-V26, low pressure core spray pump and discharge line fill pump suction line) on Division I low pressure core spray with Strut CSL-PSST-2009

Section 1R19 Postmaintenance Testing (71111.19)

Drawing DS-C-62565, “Nozzle Type Relief Valve,” Revision E

STP-000-6606, “Section XI Safety and Relief Valve Testing,” Revision 14

CR-RBS-2000-01329, RCIC lube oil cooler relief valve (E51-RVF018) lifted during slow roll of RCIC turbine following scheduled maintenance, initiated July 5, 2000

CR-RBS-2000-01333, RCIC lube oil cooling water supply pressure control valve (E51-PCVF015) is leaking and requires rebuilding, initiated July 6, 2000

CR-RBS-2000-01373, RCIC lube oil cooler relief valve (E51-RVF018) failed testing and was repaired, retested, and returned to warehouse as a spare, initiated July 17, 2000

Section 2OS2: ALARA Planning and Controls (71121.02)

Corrective Action Documents

CR-ECH-2003-00015	CR-RBS-2003-02920	CR-RBS-2003-00801
CR-ECH-2003-00347	CR-RBS-2003-03695	CR-RBS-2004-00884
CR-ECH-2004-00026	CR-RBS-2004-00092	CR-RBS-2004-00922
CR-ECH-2004-00047	CR-RBS-2004-00166	CR-RBS-2004-00924
CR-RBS-2003-00012	CR-RBS-2004-00255	LO-RLO-2003-00004
CR-RBS-2003-00566	CR-RBS-2004-00257	LO-ELO-2003-00017
CR-RBS-2003-01213	CR-RBS-2004-00259	LO-RLO-2003-00190
CR-RBS-2003-02623	CR-RBS-2004-00388	LO-RLO-2003-00191
CR-RBS-2003-02811	CR-RBS-2004-00473	LO-RLO-2003-00198
CR-RBS-2003-02847	CR-RBS-2004-00475	LO-RLO-2004-00004
CR-RBS-2003-02869	CR-RBS-2004-00548	LO-RLO-2004-00101
CR-RBS-2003-02901	CR-RBS-2004-00639	LO-RLO-2004-00107

Audits and Self-Assessments

QA-15-2003-RBS-1-Multi, Quality Assurance Audit Report-Radwaste

QS-2003-RBS-012, River Bend Station Surveillance, Radiation Work Permit Dose Extensions

QS-2003-ENS-017, Surveillance Report, Radiation Protection Warning Flag Assessment

Shielding Requests

93-0010, 95-0017, 95-0021, and 98-0001

Radiation Work Permits

2003-1003	General Chemistry Activities
2003-1028	Reverse Osmosis Walkdowns and Implementation
2004-1011	Declared Pregnant Individuals
2004-1090	Repair/peening & Leak seal injection of reactor water cleanup valve
2004-1108	Fuel Inspection/Reconstitution of 29 Fuel Bundles

Procedures

ADM-0046	Shielding Control Program	Revision 5
LI-102	Corrective Action Process	Revision 4
PL-182	Radiation Protection Expectations and Standards	Revision 1
RBNP-024	Radiation Protection Plan	Revision 10B
RP-107	Radiation Protection Glossary	Revision 2
RP-108	Radiation Protection Posting	Revision 2
RP-109	Hot Spot Program	Revision 0
RP-110	ALARA Program	Revision 1
RP-205	Prenatal Monitoring	Revision 2

Other

ALARA Committee Minutes for March 18, 2004

Section 4OA2 Identification and Resolution of Problems (71152)

Archived Operator Logs February 21 through July 17, 2003

MAI 365266, Repair the auxiliary building roof leak on elevation 171', work complete on June 17, 2003

MAI 369867, Major clean and inspect of Switchgear EJS-SWG2A ACB023, work complete March 15, 2003

CR-RBS-1995-00021, water is dripping on safety-related Switchgear EJS*LDC2A from ceiling above 141' elevation in the auxiliary building, initiated January 10, 1995

CR-RBS-2002-00847, the roof of the auxiliary control room exhibited severe leakage during thunderstorm on June 20, 2002, and this is a recurring condition, initiated June 20, 2002

CR-RBS-2002-01675, the annulus mixing fan area auxiliary building roof-top equipment removal plug is leaking water into the auxiliary building, initiated October 28, 2002

CR-RBS-2002-01929, auxiliary control room roof is leaking into the auxiliary control room. This is a repeat condition whenever the river bend station receives sustained amounts of rain, initiated December 4, 2002

CR-RBS-2003-00201, found signs of moisture on Switchgear EJS-SWG2A, initiated January 23, 2003

CR-RBS-2003-00908, a hard ground fault was detected on Switchgear ENB-SWG1B. A special ground detection machine was obtained from Grand Gulf Nuclear Station and found the fault was on Division 1 Hydrogen Recombiner HCS-RBNR1, initiated March 12, 2003

CR-RBS-2003-01550, Switchgear EJS-SWG2A ACB22 tripped while in service. During troubleshooting found evidence of prior water intrusion on the internal breaker components, initiated March 31, 2003

CR-RBS-2003-01654, the roof leak that caused the recent ground on Swithgear EJS-SWG2A appears to originate from the fresh air supply cubicle on the auxiliary building roof above the 141' elevation, initiated April 5, 2003

CR-RBS-2003-01726, auxiliary control room roof is again leaking into the auxiliary control room, initiated April 8, 2003

CR-RBS-2003-02379, found ground fault relay flag tripped on Switchgear EJS-SWG2A, initiated June 5, 2003

CR-RBS-2003-02564, water is leaking on control switches in auxiliary control room and has been documented in seven condition reports and five maintenance action items and has not been remedied, initiated August 6, 2003

CR-RBS-2004-00346, auxiliary building roof leak caused ground fault on Division 1 125 Vdc Switchgear ENB-SWG01A, initiated on February 5, 2004.

CR-RBS-2004-00352, during heavy sustained rainfall, auxiliary building roof is allowing rainwater to leak into AB 141' elevation in standby gas treatment Room B, 141' elevation adjacent to NHS-MCC102B and EJS*SWG2A, initiated February 5, 2004

CR-RBS-2004-00353, condition report (CR-RBS-2003-1654) was closed to an MAI to fix a set of leaking plugs in the overhead of auxiliary building 171' elevation. That MAI was worked and closed while the CR closed to it was not satisfied. A ground on Switchgear EJS-SWG2A was received today that may have been prevented if the scope of the MAI had been changed to include the sources of the rainwater leakage over EJS-SWG2A as presented in CR-RBS-2003-1654, initiated February 5, 2004

CR-RBS-2004-00354, auxiliary building is again leaking into the auxiliary control room, initiated February 6, 2004

CR-RBS-2004-00479, rainwater leakage is coming from the auxiliary building/reactor building interface, initiated February 15, 2004

Section 4OA3 Event Followup (71153)

CR-RBS-1997-02003, temperature cables for external LEFM landed on wrong terminals, initiated November 10, 1997

CR-RBS-1998-00809, external LEFM transducer coupling compound between the wedge and transducer unreliable because it drys out, initiated June 26, 1998

CR-RBS-1998-01135, external LEFM transducers experience accelerated aging and reliability problems due to feedwater line temperature and temperature changes during mode changes, initiated September 1, 1998

CR-RBS-2002-00741, data from external LEFM unacceptable (would require correcting venturi data by more than 2 percent) for establishing new correction factors, initiated May 22, 2002

CR-RBS-2002-01408, data from external LEFM erroneous following startup from forced outage 02-02

LIST OF ACRONYMS

ALARA	as low as is reasonably achievable
AOP	abnormal operating procedure
CFR	*Code of Federal Regulations*
CR-RBS	River Bend Station condition report
ECCS	emergency core cooling system
EOP	emergency operating procedure
HPCS	high pressure core spray
LEFM	leading edge flow meter
LER	licensee event report
MAI	maintenance action item
NCV	noncited violation
NRC	U.S. Nuclear Regulatory Commission
PI	performance indicators
RFO	refueling outage
RHR	residual heat removal
RCIC	reactor core isolation cooling
RPV	reactor pressure vessel
SSC	structures, systems, or components
STP	surveillance test procedure
USAR	Updated Safety Analysis Report
WO	work order