UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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February 10, 2005

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

SUBJECT: RIVER BEND STATION - SPECIAL INSPECTION REPORT 05000458/2004012

Dear Mr. Hinnenkamp:

On October 8, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed a Special Inspection at your River Bend Station. The enclosed inspection report documents the inspection findings, which were discussed on December 16, 2004, with you and other members of your staff. On January 14, 2005, a subsequent telephonic discussion was held with Mr. R. King and other members of your staff to convey the final disposition of those inspection findings.

The inspectors examined activities associated with a loss of the Reserve Station Service Line 1, the main generator output line, that resulted in a reactor scram and subsequent system interactions that occurred on October 1, 2004. The inspection was conducted in accordance with Inspection Procedure 93812, “Special Inspection Procedure,” and the inspection team charter. The inspectors reviewed selected procedures and records, evaluated activities, and interviewed personnel.

This report documents two self-revealing findings of very low safety significance (Green). One of these findings was determined to involve a violation of NRC requirements. However, because of the very low safety significance and because it is entered into your corrective action program, the NRC is treating this finding as a noncited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. If you contest any NCV in this report, 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 Region IV; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 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 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 05000458/2004012
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-458
License:	NPF-47
Report No:	05000458/2004012
Licensee:	Entergy Operations, Inc.
Facility:	River Bend Station
Location:	5485 U.S. Highway 61 St. Francisville, Louisiana
Dates:	October 4-8, 2004
Inspectors:	A. A. Sanchez, Resident Inspector, Project Branch A, Team Leader J. F. Drake, Operation Engineer, Operation Branch P. J. Alter, Senior Resident Inspector, Project Branch B
Approved By:	D. N. Graves, Chief Project Branch B Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000458/2004012; 10/04/2004 - 10/08/2004; River Bend Station; Special Team Inspection

The report covered a period of inspection by three inspectors and an NRC risk analyst. One Green NCV and one Green finding were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, “Significance Determination Process.” Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors documented a self-revealing finding for failure to adequately maintain the circulating water cooling tower drift eliminators which resulted in salt contamination of the insulators in the onsite transformer yard. This contamination caused ground faults on RSS Line1 and main transformers, which resulted in the loss of the Division I offsite power and a reactor scram on October 1, 2004. This finding had crosscutting aspects of problem identification and resolution in that corrective actions were not taken in a timely manner following identification of the degraded cooling towers, and that corrective actions were not implemented in a timely manner following reaching the self-imposed limit for insulator arcing. The failure to take timely action to clean the insulators or take the transformers off-line resulted in the transformer trips and subsequent reactor scram.

  This finding is 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. A completed Phase 3 evaluation resulted in an incremental conditional core damage probability of 1.2E-7. Therefore, the significance of the finding was determined to be of very low safety significance (Section 3.5.1).

Cornerstone: Mitigating Systems

- Green. The inspectors documented a noncited violation of Technical Specification 5.4.1.a for the failure of the licensee to implement Abnormal Operating Procedure AOP-0005, “Loss of Main Condenser Vacuum/Trip of Circulating Water Pump,” following the loss of two of three operating circulating water pumps. Failure to implement this procedure contributed to a loss of condenser vacuum. This finding had crosscutting aspects of human performance (personnel) in that the operators did not implement the abnormal operating procedure as required. Additionally, this finding had crosscutting aspects regarding problem identification and resolution (identification) in that a similar event had occurred over a month earlier and no actions were taken to incorporate that operating experience into the operating procedures or enter it into the corrective action program.

This finding is greater than minor because it is associated with human performance attribute of the mitigating system cornerstone and affects the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This finding actually led to the loss of main condenser vacuum and forced the operators to perform a reactor cooldown through safety relief valves, reactor core isolation cooling, and the suppression pool. This finding is of very low safety significance because it would only affect the plant during this particular situation of partial loss of offsite power and all mitigating capability was maintained (Section 3.4.1).

B. Licensee-Identified Findings

A violation of very low safety significance, which was identified by the licensee has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee’s corrective action program. This violation and corrective actions are listed in Section 4OA7 of this report.

CONTENTS

REPORT DETAILS

1.0 INTRODUCTION

1.1 Special Inspection Scope

The NRC conducted this inspection to gain a better understanding of the circumstances surrounding the loss of the Reserve Station Service (RSS) Line 1 (Division I emergency offsite power) and the main transformer output line due to ground faults on the morning of October 1, 2004, at the River Bend Station. The loss of the main transformer also caused a reactor scram. The inspection also reviewed subsequent equipment and system issues associated with the reactor core isolation cooling (RCIC) system isolation after receiving a demand signal, Level 8 reactor scram signals while the mode switch was in the SHUTDOWN position, and the loss of the steam side of the power conversion system (PCS) due to condenser vacuum problems.

The inspection team used NRC Inspection Procedure 93812, “Special Inspection Procedure.” The specific items for investigation were outlined on the special inspection team charter, provided as Attachment 2. The special inspection team reviewed procedures, corrective action documents, work requests, historical inspection reports for systems of concern, and root cause analysis reports. The team also interviewed key station personnel regarding the event, the root-cause analysis, and corrective actions. A list of personnel interviewed and documents reviewed are provided as Attachment 1.

1.2 Preliminary Significance of Event

The NRC staff considered both deterministic and safety significance criteria, established in NRC Management Directive 8.3, “NRC Incident Investigation Program,” to determine whether a special inspection would be performed. The NRC staff determined that the following two deterministic criteria were met: (1) the loss of condensate and feed systems, the unexpected isolation of the RCIC system due to a steam line differential pressure, the loss of PCS due to vacuum problems, and mode switch problems associated with unexpected Level 8 reactor scram signals involved multiple failures in systems used to mitigate an actual event; and (2) the unexpected RCIC isolation and reactor scram at Level 8 with the mode switch not in Run involved significant unexpected system interaction.

An NRC senior reactor analyst performed a preliminary risk assessment using the NRC’s standard plant analysis risk (SPAR) model. The risk assessment conservatively assumed that: (1) offsite power was unavailable for 8 hours for RSS Line1, (2) a loss of the steam side of PCS, (3) the feedwater side of PCS was recoverable, (4) the condensate system remained available, and (5) the RCIC system isolated but was also recoverable. The results from the SPAR model estimated the incremental conditional core damage probability (ICCDP) of $2.0X10^{-6}$ to $9.0X10^{-6}$ depending on best and worse case assumptions for RCIC, respectively.

The ICCDP was at the value for consideration for a special inspection. Based on the deterministic criteria that were met and the ICCDP value, NRC management determined that a special inspection was warranted to further examine the circumstances surrounding the event.

2.0 EVENT DESCRIPTION

2.1 Event Background

Since April 2003, the River Bend Station had been experiencing a degradation of the circulating water cooling tower drift eliminators. This was evident by various condition reports documented in the corrective action program. The condition being reported was that a film was being deposited around the site from the moisture carryover of the circulating water cooling tower drift.

On August 19, 2004, the licensee observed arcing on the 230 kV line insulators one span out from the site transformer yards. The arcing was only occurring in the presence of the cooling tower drift. The arcing on the high voltage insulators is known as the corona effect. All high voltage lines and their connection to insulators experience some degree of corona. Corona is the buildup of charges caused by partial ionization of the air surrounding an insulator and its physical connection to the high voltage line. Arcing normally occurs where the charges are accumulated, such as metal connectors with sharp edges. Insulators are not only physically located further away from these connectors, but they also do not contain sharp edges and should not experience corona. Insulators are also coated with a sealant that smooths the surface and resists charge buildup. Corona is mainly heard as a crackling or hissing sound during instances of moist weather conditions such as fog or morning dew. Other ways to detect corona is through a corona camera, or by measuring temperature of the insulators and connectors. If an insulator becomes degraded, by contamination or surface defects, the corona effects can become visible to the naked eye. In the case at RBS, the insulators were contaminated by the cooling tower drift. The drift left a salt film on the insulators, which has conducting properties.

The licensee consulted with various industry experts, continued to monitor the corona activity, and implemented a compensatory action plan. The plan imposed two quantitative trigger points for arcing intensity on all site insulators. Action was required at each of the trigger points. On September 22, 2004, the second trigger point was reached for insulators in Transformer Yard 1. The arcing activity completely jumped the first trigger point. The licensee was not able to immediately implement the compensatory action for the second trigger point. This set the stage for the series of ground faults that took place the morning of October 1, 2004, amid heavy cooling tower drift and extremely foggy conditions in Transformer Yard 1.

2.2 Event Summary

On October 1, 2004, at 7:18 a.m., the River Bend Station lost RSS Line 1 due to a fault on the line insulators. The loss of RSS Line 1 caused a loss of the Division I emergency bus which was being supplied from offsite power through RSS Line 1. The Division I emergency diesel generator started and loaded as designed.

While recovering from that loss, at 7:30 a.m., a fault was sensed in the main transformer which resulted in a main generator trip/lockout and a reactor scram. The electrical faults resulted in the loss of main feedwater and condensate systems' ability to provide primary makeup water to the reactor. The RCIC system experienced a steam supply isolation during the reactor scram. Within 30 minutes of the reactor scram, both inboard and outboard main steam isolation valves (MSIVs) were closed by the operators due to lowering main condenser vacuum. The reactor operators stabilized the plant using high pressure core spray and safety relief valves (SRVs). The plant was cooled using SRVs, RCIC, and the shutdown cooling mode of the residual heat removal system.

3.0 SPECIAL INSPECTION AREAS

3.1 Sequence of Events (Charter Item 1)

a. Inspection Scope

The inspectors developed a sequence of events related to the fault on RSS Line 1 and subsequent fault on the main transformer, which led to the reactor scram on October 1, 2004. The inspectors constructed a sequence of events through review of the plant computer data (where available) and plant parameter printouts (postaccident monitoring system), operator logs, and interviews with the licensee's staff. The inspector-developed sequence of events was compared with the licensee's sequence of events to determine whether the event had been adequately captured and reviewed.

b. Findings and Observations

No findings of significance were identified.

3.2 Posttrip Review (Charter Item 3)

a. Inspection Scope

The inspectors reviewed the licensee's posttrip review. This review included an evaluation of the thoroughness of the licensee's assessment of the event, proper consideration for the extent of condition, immediate corrective action for equipment and system issues, and whether it was in accordance with approved procedures. The inspectors also attended two Operational Safety Review Committees (OSRC) meetings. The OSRC is the organization that was responsible for reviewing and approving the completed scram recovery checklist prior to reactor startup.

b. Findings and Observations

No findings of significance were identified. The inspectors determined that the licensee adequately and thoroughly reviewed the reactor scram and associated equipment issues. The licensee properly considered the extent of condition and took appropriate immediate corrective action prior to reactor startup. The posttrip review was documented and reviewed by the OSRC in accordance with General Operating Procedure GOP-0003, “Scram Recovery,” Revision 15. The equipment issues that were reviewed and resolved prior to startup are discussed in detail in Section 3.3.

3.3 Equipment Performance and System Responses (Charter Item 6)

a. Inspection Scope

The inspectors reviewed the plant response to the partial loss of offsite power, loss of the main generator, and reactor scram. The team reviewed operator logs, corrective action documents, work requests, and work orders attended OSRC meetings, and interviewed system engineers and operators. The inspectors also reviewed the completed and proposed long-term corrective action for these issues.

b. Findings and Observations

No findings of significance were identified. The inspectors evaluated the following equipment and system issues:

.1 RCIC System Isolation

Immediately following the reactor scram, the RCIC system was discovered to be isolated due to a Division 2 high steam line differential pressure indication that occurred coincident with the main turbine trip and reactor scram. The differential pressure signal cleared almost immediately. Operators took timely and appropriate actions to manually isolate the RCIC system, and to warm it up for use in accordance with station operating procedures.

The high steam line differential pressure detection system configuration is unique at every plant. The sensing lines for this detection system originate from elbow taps on the RCIC steam line in the drywell where the pipe transitions from horizontal to vertical. The low-side pressure tap is located on the bottom of the steam line pipe, while the high-side pressure tap is on the top of the pipe. The common sensing lines run to an instrument rack for Rosemount Transmitter E31-N084B, then to a high point and down to an instrument rack for Rosemount Transmitter E31-N084A.

The licensee used a Kepner-Tregoe (KT) problem analysis procedure to determine that the most probable cause of the RCIC high steam line differential pressure isolation was a partially blocked low pressure sensing line to Transmitter E31-N084B. The blocked low pressure sensing line would act to slow the signal from reaching the low side of the transmitter, while the high pressure sensing line would detect the pressure transient. This would produce a high differential pressure transient and subsequent RCIC isolation.

A review of the Emergency Information Response System (ERIS) data indicated that the differential pressure peaked at approximately 92 inches for Transmitter E31-N084B and decayed over a 5-second time period. The isolation setpoint was set at 60.7 inches. By comparison, parallel Transmitter E31-N084A indicated a smaller, but downward spike in differential pressure of approximately 10 inches and a similar 5-second decay time. The fact that the transmitters were exposed to the same steam line pressures via the shared sensing lines, but responded in stark contrast, indicates that there was a difference in the line between the two transmitters. The licensee postulated that the most probable cause for this difference in indication was the existence of a noncondensable gas bubble located at the high point between the two transmitters. The licensee theorized that the reactor scram of August 15, 2004, and depressurization to 500 psig allowed a small amount of noncondensable gases to accumulate in the sensing lines. The noncondensable gases would act to slow the pressure transient from reaching the high pressure side of the transmitter, while the low pressure side would see the pressure transient and not be delayed. This would cause the transmitter to see a negative differential pressure.

The corrective action taken included establishing preventive maintenance (PM) to perform a high velocity flush of the sensing lines every refueling outage to remove any particles, and a procedure change to perform a high point vent for the two transmitters. The licensee also plans to evaluate the removal of the steam line high differential pressure detection system altogether.

.2 Mode Switch and Level 8 Half-Scrams

After the reactor scrammed on October 1, 2004, the mode switch was taken from the RUN position to the SHUTDOWN position as required. During the course of the event, several Level 8 signals were received and caused reactor half-scams, RCIC, and feedwater isolations. This was not expected because the mode switch was designed to bypass the Level 8 signal when the mode switch is in any position besides RUN.

The licensee determined that normally energized Agastat Relay C71A-K24C, Model EPG, was the cause for the Level 8 half-scrams. The relay used two sets of contacts. One set of contacts, T1-M1, closes to increase the Average Power Range Monitor G setpoints when the mode switch is in the RUN position. The other set of contacts, R2-M2, closes when the mode switch is in the RUN position to enable the reactor protection system (RPS) Channel C Level 8 scram when the reactor is at power. The R2-M2 set of contacts failed to fully open when the mode switch was placed into the SHUTDOWN position and the relay de-energized. This failure allowed the Channel C Level 8 scram to remain in the RPS circuitry.

The licensee determined that the cause for the failure was a dirty set of contacts. This relay is considered to be low-safety critical and fail-safe when the normally-energized relay is de-energized. The failure of the relay is self-revealing and, in this instance, revealed itself via the half-scram. This relay is in the licensee's PM program and is scheduled for performance testing every 6 years and replacement every 13 years. This relay is actually tested every 18 months during refueling outages. The licensee reviewed the recent failures of normally-energized Agastat relays and have concluded that the failure rate of these relays over the past 8.5 years ($4.70X10^{-7}$ failures per hour) are well within the expected failures per design ($1.0X10^{-6}$ failures per hour).

The licensee has begun to systematically review the PM for relays site wide under a PM Optimization Project. The failed relay was replaced and the new relay was tested satisfactorily.

.3 Emergency Response Information System (ERIS)

The ERIS system supplies plant information to the control room, specifically the control room supervisor's (CRS) desk. The CRS would rely, in part, on this system for plant conditions and as an aid to help guide his/her actions and decisions. During the event on October 1, 2004, the ERIS system functioned intermittently. This led to incorrect and delayed information being displayed on the ERIS computer screen. The CRS continued to rely on the information supplied by ERIS and subsequently caused complications in operators' performance during the event.

The licensee has narrowed the cause of the intermittent operations of the ERIS system to the Inverter BYS-INV06 power supply. The power supply to the inverter is normally via the normal station transformer, but had been on static bypass since July 29, 2004. The inverter will automatically swap to the bypass power source, but the swap from the bypass to the normal power source requires a manual action. RSS Line 1 supplied the alternate power to the inverter through the static bypass switch and, when RSS Line 1 was lost, so was power to ERIS. Work Order WO-36425 was written to investigate and correct the problem.

3.4 Operator Response (Charter Item 5)

a. Inspection Scope

The inspectors assessed emergency and abnormal procedure implementation and control room operator response to the loss of RSS Line 1, the loss of the main transformer, and the plant system and equipment performance. The inspectors reviewed corrective action documents, procedures, operator logs, and plant parameters and interviewed the operations staff that responded to the event, as well as operator training and simulator personnel.

b. Findings and Observations

.1 Introduction. A Green self-revealing noncited violation (NCV) was identified for violation of Technical Specification 5.4.1.a for failure to implement the Abnormal Operating Procedure (AOP) AOP-0005, “Loss of Main Condenser Vacuum/Trip of Circulating Water Pump.”

Description. On October 1, 2004, the loss of RSS Line 1 and the main transformer due to ground faults led to the loss of Division 1 power and to a reactor scram. The operations staff was prepared for a possible loss of RSS Line 1 power due to the corona effects and the planned insulator cleaning activities that were scheduled to take place that day. Various loads had been transferred to other buses supplied by RSS Line 2 as a precautionary measure. At the time of the event, the licensee was operating the circulating water system in an abnormal configuration (three pumps operating instead of four) due to maintenance on one of the circulating water pumps. At 7:18 a.m. the loss of RSS Line 1 line of offsite power resulted in a loss of one half of the balance of plant equipment. Included in this loss were circulating water Pumps A and C and their motor-operated discharge valves. Circulating water Pump D was the only pump in operation, but most of its discharge was bypassing the main condenser and was recirculating back through circulating water Pumps A and C.

At 7:30 a.m., 12 minutes after the loss of RSS Line 1, the reactor scrammed due to a ground fault on the main transformer. The main turbine bypass system automatically diverted the reactor decay heat to the main condenser. Main condenser vacuum was observed to be deteriorating. The CRS directed a reactor operator to complete actions in accordance with Procedure AOP-0005, “Loss of Main Condenser Vacuum/Trip of Circulating Water Pump.” The reactor operator failed to locate the proper procedure and implemented Standard Operating Procedure (SOP) SOP-006, “Circulating Water, Cooling Tower, and Vacuum Priming,” in lieu of the AOP. Procedure SOP-006 was not the proper procedure to be used given the plant condition, nor were the precautions and limitations of the procedure reviewed and followed.

Due to possible run out conditions for the lone operating circulating water pump, operators isolated three condenser water boxes even though Procedure SOP-006 did not outline single pump operation. An important precaution listed in the procedure specifically forbids the operation of steam line drains or turbine bypass valves into the condenser if any water box is isolated. Operations personnel continued to admit steam to the main condenser through the main steam drain lines, which complicated operator actions and accelerated the decline in main condenser vacuum. Operators received repeated isolations on low condenser vacuum and eventually placed the low vacuum bypass switches in BYPASS. This action resulted in blocking the protective isolations and allowed the condenser to become pressurized.

Analysis. The failure to implement Procedure AOP-0005, “Loss of Main Condenser Vacuum/Trip of Circulating Water Pump,” was a performance deficiency. This finding was determined to be more than minor because it is associated with the human performance attribute of the mitigating system cornerstone and affects the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding degraded the ability for short-term heat removal under the mitigating systems cornerstone. The finding represented a loss of the steam side of the PCS safety function, which is Question 2 under the Mitigating System Cornerstone column of the Phase 1 worksheet.

A Phase 2 analysis was completed with assistance from a Senior Reactor Analyst (SRA) in Region IV. Because this particular finding would only affect the plant during this specific situation of partial loss of offsite power, only the loss of offsite power initiating event sequences were evaluated. Per the SRA, the PCS was added to the sequences and assigned a mitigating capacity value of one. This finding was determined to of very low safety significance based on the fact that, in all worksheet sequences, full mitigation capability was maintained.

The inspectors have also identified a Human Performance crosscutting aspect to the finding. An operator was specifically tasked with the implementation of Procedure AOP-0005 and, not only did that operator fail to locate the procedure, but the decision to use Procedure SOP-006 procedure in its place was made at a crew consensus level. The failure to locate the correct procedure and the decision to use another, improper, procedure were human performance errors (personnel). The Human Performance crosscutting aspect of this finding is referenced in Section 4OA4.

Additionally, the inspectors identified a Problem Identification and Resolution crosscutting aspect to the finding. A similar event occurred on August 15, 2004, in which at least two individuals were aware of the need to close the circulating water pump discharge valves upon the loss of one division of offsite power. No actions were taken to incorporate that operating experience or to place the issue into the corrective action program until after the October 1 event. The Problem Identification and Resolution crosscutting aspect of this finding is also referenced in Section 4OA2.

<u>Enforcement</u>. Technical Specification 5.4.1.a states, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedure recommended in Regulatory Guide 1.33, Appendix A, Revision 2. Regulatory Guide 1.33, Appendix A, Section 6.e, requires procedures for combating emergencies and other significant events, including a loss of condenser vacuum. In contrast to this requirement, the operations staff failed to implement Procedure AOP-0005, “Loss of Main Condenser Vacuum/Trip of Circulating Water Pump,” which led to a complete loss of condenser vacuum following the trip of two of the three operating circulating water pumps. Because the failure to implement this procedure was determined to be of very low safety significance and has been entered into the licensee’s corrective program, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000458/20040012-01; Technical Specification 5.4.1.a violation for failure to implement a required procedure for loss of main condenser vacuum.

.2 Reactor Coolant System Level 2 Actuation

At approximately 7:35 a.m., the operators closed the outboard MSIVs due to lowering main condenser vacuum. At 7:58 a.m., the inboard MISVs were closed, also due to lowering main condenser vacuum. This was an anticipatory action taken with at least an 8.5-inch vacuum remaining in the main condenser. Reactor pressure was being controlled by the SRV low-low set function. At 8:04 a.m. level control was assigned to the At The Controls (ATC) operator who was working on restoring feedwater. At 8:10 a.m., SRV F0551D opened on low-low set and the control switch was taken to the OPEN position to bring pressure to the low end of the pressure band; the band was set at 500-1090 psig. At this point, through licensed operator interviews, the inspectors determined that it was not clear who had pressure control or which operator placed the SRV control switch in the OPEN position. The root cause investigation stated that the ATC operator had responsibility for both level and pressure control. This is a difference between the team's investigation and the licensee's root cause.

At 8:14 a.m. a Level 3 was reached. The SRV remained open until 8:16 a.m. when the ATC operator reported that the reactor pressure vessel (RPV) level was decreasing and approaching the Level 2 setpoint. An operator was instructed to close the open SRV, while another operator was directed to inject with high pressure core spray. The closure of the SRV promptly dropped level to -52 inches, which exceeded the Level 2 setpoint of -43 inches. The only remaining recirculation pump tripped. Feedwater Pump FWS-P1C was started. Within one minute, RPV level was restored above the Level 2 setpoint and restored above the Level 3 setpoint within 3 minutes. During this time, the CRS was observing the ERIS display for RPV level and did not notice any change because of the power loss to that system.

The Level 2 that was experienced by the operators was not expected, nor should it have occurred. There were at least three contributing causes for the Level 2. First, the ATC operator should not have had responsibility for both level and pressure control. Second, communication between the ATC operator and the SRV operator was not sufficient to limit unexpected RPV level fluctuations. At the time of the incident, all MSIVs were closed and the ATC operator was in the process of restarting a feedwater pump. According to the RBS's pressure control strategy, pressure should have been controlled via the main steam line drains or through cycling SRVs. If SRV cycling is to be used, then close coordination between the ATC operator and the SRV operator should take place to limit unexpected level fluctuations. Contrary to this, an operator placed the SRV into the OPEN position and walked away from the control board without sufficient coordination with the ATC operator. The third contributing cause was that the CRS relied on the ERIS display that was not functioning properly. The CRS was cognizant that the ERIS system was suspect, but continued to rely on the system output. According to the ERIS display at the time of the Level 2, level was not changing.

.3 Communication Issues and Procedure Usage

The inspectors identified several instances of miscommunication among the operations staff, and inadequate procedure usage. Although these observations complicated operator actions in responding to the event, none of these observations represent findings or violations of NRC requirements. The following are examples of these observations:

- The inspectors identified a weakness in the use of procedures. Operators failed to properly implement and follow Procedures SOP-006, “Circulating Water, Cooling Tower, and Vacuum Priming,” and AOP-003, “Automatic Isolations.” Procedure SOP-006 was not written for the plant conditions experienced that day. This procedure was used because the operator could not find Procedure AOP-0005 for loss of main condenser vacuum and the trip of circulating water pumps. The operators also failed to follow the precautions and limitations for this procedure’s use. As a result, steam was admitted to the main condenser after three water boxes were isolated, in direct contradiction to procedural guidance.

  Procedure AOP-003 actions for independent verifications of main condenser vacuum were not performed following the low vacuum signal reset and prior to reopening the main steam line drains. This action was again in contradiction to the procedural guidance. The main steam line drains should not have been reopened. This action helped accelerate the loss of the main condenser vacuum.

- The shift manager on October 1, 2004, was the same shift manager on shift for the August 15, 2004, reactor scram that was caused by the loss of RSS Line 2 of offsite power. During the August 15 event, two of the circulating water pumps and motor-operated discharge valves lost power. The outside operator noticed that the discharge valves were open and had to be manually closed or electrically cross-tied in order to close them. Procedure AOP-0005 did not give clear guidance to close the discharge valves if power is removed. This point of improvement was not identified in the event critique and was not corrected until after the October 1 event.

- There were too many individuals (15-17 people) in the control room during stabilization of the reactor during the event which led to miscommunication and confusion in the control room.

- The outside operator failed to communicate information concerning the circulating water system and the apparent restart of the failed circulating water pumps to the control room. This communication would have led operations to determine that the circulating water pumps were not in operation, and were indeed rotating backwards, and condenser cooling was bypassed.

- The CRS relied too heavily on the ERIS system for information and decision making even though the information was suspect and not dependable.

3.5 Root Cause Evaluations and Corrective Actions (Charter Item 4)

a. Inspection Scope

The inspectors reviewed the licensee's two root cause analyses. The licensee assembled two Significant Event Response Teams (SERTs) to evaluate the causes of the events that occurred on October 1, 2004. SERT 1 was charted to evaluate the isolation of the 230 kV transmission line, RSS Line 1, and the plant scram caused by the fault on the main transformer output line. SERT 2 was chartered to evaluate the operator and plant response to the loss of RSS Line 1 and reactor scram.

The inspectors reviewed the reports and the root cause analyses for technique, accuracy, thoroughness, and corrective actions proposed and taken. The inspectors reviewed the scope and processes used by licensee personnel to identify the root cause for the loss of the RSS Line 1 line and the main generator output line and differential steam pressure isolation of the RCIC system. The inspectors compared the information gained through inspection to the event information and assumptions made in the reports.

b. Findings and Observations

.1 Introduction. A Green, self-revealing finding was identified for failure to adequately maintain the circulating water cooling tower drift eliminators, which resulted in salt contamination of the insulators in the on-site transformer yard. This contamination caused ground faults on RSS Line1 and main transformers, which resulted in the loss of Division I offsite power and a reactor scram on October 1, 2004.

Description. For over a year the licensee was aware of the degrading conditions of the circulating water cooling towers. This was evident through a number of corrective action documents that discuss the excessive moisture carryover in the cooling tower drift that led to film deposits on employee vehicles near the cooling towers. Other condition reports discuss cooling tower inspection results in which drift eliminators were missing.

On August 19, 2004, the first condition report was generated that specifically discussed the arcing that was taking place on the 230 kV line insulators one span out from the RBS transformer yards. On September 8, 2004, arcing was again documented in a condition report for arcing on the same 230 kV line insulators, but also noted was the presence of the cooling tower drift directly over the 230 kV tower, which appeared to promote the arcing. As of September 10, 2004, the licensee had implemented the Operational Decision Management Issue (ODMI) to monitor the arcing activity of the line insulators. This document was modified two times within the following 4 days after consultation with transmission managers and an Electric Power Research Institute (EPRI) representative. The final revision of the guideline set specific trigger points for which specific compensatory measures would be placed into action. Trigger Point 1 was visible arcing over 40 percent of an insulator. Trigger Point 2 was set at arcing over 50 percent of an insulator.

On September 22, 2004, Trigger Point 2 was reached as arcing was reported to be approximately 66 percent of a line insulator in 230 kV Transformer Yard 1. The ODMI outlined a course of action to consider de-energizing the line and have the insulators cleaned. The licensee was subsequently able to schedule a vendor to clean the insulators while the line remained energized. The vendor arrived on site and cleaning was scheduled for September 29, but the insulated bucket truck was not certified for the higher 230 kV lines at RBS. The truck failed the initial test certification and required rework before eventually passing testing certification. Cleaning was rescheduled for October 1. Operations and management prepared for the cleaning activity, and the potential to lose RSS Line 1, by moving all loads to alternate power sources, where applicable. Operators were also provided just-in-time training that simulated the worst-case scenario for losing RSS Line 1.

On the morning of October 1, the site was engulfed in a dense fog and the cooling tower effluent was directly over Transformer Yard 1. At 7:18 a.m., RSS Line 1 tripped. Operations was prepared for that failure and took appropriate action to maintain safe, stable plant operations. At 7:30 a.m., a ground fault on the main generator output line caused a generator lock-out and a reactor scram.

Analysis. The inspectors determined that the failure to maintain the circulating water cooling tower drift eliminators was a performance deficiency. This finding is more than minor because it was associated with the equipment performance attribute of the initiating events cornerstone and affects the initiating event 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.

Manual Chapter 0609, “Significance Determination Process,” Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” was used to evaluate the finding. Phase 1 was performed and it was determined that, because the finding was a transient initiator contributor under the initiating events cornerstone and degraded the short-term high pressure heat removal capability under the mitigating systems cornerstone, a Phase 2 evaluation was required to be performed. The RBS significance determination process worksheets for transients, transients without power conversion system, and loss of offsite power were solved and resulted in an initial finding of substantial safety significance. The Region IV SRAs conducted a Phase 3 evaluation.

The Phase 3 analysis incorporated the following significant assumptions: (1) the risk period began on August 19, 2004, when the corona was first observed, (2) RSS Line 2 was at a much lower risk for a contamination induced fault than RSS Line 1 and was only at risk for faulting after September 12, 2004 (although highly unlikely), and (3) five mutually exclusive outcomes were possible given the actual conditions at RBS. The five outcomes were assigned a probability of occurrence according to a Poisson distribution that incorporated a 2-day period of vulnerability for a transformer failure. Using the RBS SPAR model, Revision 3.10, in the SAPHIRE and GEM environments, the conditional core damage probability for each outcome was determined. The product of the event outcome probability and the conditional core damage probability yielded the ICCDP. Given that the possible outcomes reflect all possible outcomes, the ICCDPs for each outcome were summed to obtain the total ICCDP. This value was determined to be 1.2E-7. Therefore, the significance of the finding was determined to be of very low safety significance.

The inspectors also identified a problem identification and resolution aspect of this finding. The inspectors determined that there were sufficient opportunities to identify and correct the cooling towers prior to their degradation having a significant effect on the plant. The licensee also failed to take prompt corrective action after reaching Trigger Point 2 for action, according to the approved ODMI, to prevent adverse consequences of high voltage insulator grounding. The Problem Identification and Resolution aspects of this finding are referenced in Section 4OA2.

Enforcement. No violation of regulatory requirements occurred. The inspectors determined that the finding did not represent a noncompliance because it occurred on nonsafety-related equipment: FIN 05000458/2004012-02; Failure to maintain circulating water cooling tower drift eliminators.

.2 Root Cause for Electrical Fault on RSS Line1 and the Main Generator Lines

SERT Team 1 determined the root cause and contributing causes using the Event and Causal Factor Charting. Additional guidance from Nuclear Management Manual EM-LI-118, “Root Cause Analysis Process,” Revision 0, was also used. The root cause for the ground faults on RSS Line 1 and main generator transformer output line was the degraded circulating water system cooling tower drift eliminators. The degraded drift eliminators allowed excessive moisture carryover from the cooling tower exhaust. The excessive moisture, which mainly consisted of sodium (Sodium Chloride and Sodium Sulfate) and calcium (Calcium Sulfate), deposited a heavy film around the site and on transformer yard insulators. It was the contamination on the insulators coupled with a heavy fog that caused the lines to ground through the wetted salt contamination.

In March 2003, Marley Cooling Tower Technologies performed an inspection of the four Marley Class 700 round mechanical draft cooling towers at RBS. The vendor’s report noted areas of improvement, including approximately seven drift eliminator sections that had collapsed into the cooling tower basins. The cause was given as either a failure of the extrusion that supports the drift eliminators or the failure of the concrete nails (probably due to corrosion) that held the extrusion. The vender recommended that the defective drift eliminators be replaced and repaired and the failure rate be monitored in the future. These drift eliminators were repaired during Refueling Outage RF11 in March 2003. Since that time, the licensee had noted the apparent continued failure of drift eliminators in periodic cooling tower inspections and in the corrective action documents. Condition reports emerged during the summer of 2003, and continued through the summer of 2004, concerning a heavy white film that was being deposited on vehicles in the east parking lots. This was a clear indication of the degraded cooling tower drift eliminators. An inspection, conducted by the Nalco Company after the identification of a relationship between the cooling tower effluent and corona effects seen in the main switchyard, was completed on September 16, 2004, and revealed that numerous drift eliminators were missing from Cooling Towers A and C. The inspection report concluded, “the majority of the escaping drift into the atmosphere is a direct result of eliminators missing from tower 'A' and 'C.'”

The inspectors identified a licensee weakness in the failure to recognize the significance of the cooling tower drift on plant equipment. This was collaborated by the licensee’s root cause analysis. The licensee had multiple opportunities to prevent or mitigate the cooling tower deposits in the transformer yard that housed RSS Line 1 and the main generator transformers, but failed to perform a thorough extent of condition review for the drift problem. It was not until late September 2004, after corona effects were first observed on the insulators, that an extent of condition evaluation for the cooling tower drift was directed.

The inspectors also identified that the licensee’s lack of preparation to implement the actions of the ODMI trigger points for the amount of arcing detected on the insulators in the transformer yard contributed to the event. The ODMI had two trigger points for action. Trigger Point 1 was set at observed arcing across 40 percent of any one stud insulator. Actions at this point included contacting cleaning contractors and evaluating cleaning options. Trigger Point 2 was set at observed arcing across 50 percent of any one stud insulator. The associated Trigger Point 2 actions consisted of considering de-energizing the affected lines, considering protecting equipment supplied by unaffected lines, and considering transferring affected loads to a normal station service transformer. Trigger Point 2 was reached on September 22, 2004. The licensee did not expect to reach Trigger Point 2 and did not have a cleaning contractor prepared to clean the energized line. Before the contractor could mobilize to the plant with the proper equipment, grounds were experienced on the RSS Line 1 and main generator transformer.

The inspectors believe that the failure of the licensee to be prepared for the cleaning activities upon reaching the action trigger points was due to the failure to account for the rate of contamination accumulation on the insulators. Because the licensee did not account for this rate, they assumed that they would reach Trigger Point 1 prior to reaching Trigger Point 2 with some time in between. This was not the case and the licensee did not have time to qualify the insulator cleaning equipment after reaching the second trigger point. Previous versions of the ODMI were more conservative than the current version in how the arcing was categorized. This apparent move towards nonconservatism occurred after continued discussions with EPRI and fleet calls with other Entergy facilities and the Entergy substation equipment, transmission line, and transmission line design managers. In none of the documents reviewed by the inspectors was the rate of contamination deposition a topic of consideration. After reviewing the documentation and interviews with personnel involved in this issue, the inspectors concluded that the consultants gave general recommendations based upon their experience and the recommendations were not specific to RBS given the rate of accumulation that existed at that time.

The inspectors concluded that a reasonable estimate for the rate of contamination accumulation could have been made by the licensee. Supporting facts for this include: insulator tests performed during Refueling Outage RF11, the continually degrading conditions of the cooling towers, the corrective action documents reporting heavy film deposits, and the recent dry weather conditions. The licensee performed Doble “hot collar” tests (a measure of leakage current across a portion of the transformer bushing) for all transformers in Transformer Yard 1 during Refueling Outage RF11 (March-April 2003), and found no adverse impact due to existing levels of contamination. This was actually a baseline condition for the contamination accumulation. The fact that the cooling towers were degrading at a rate not before seen at RBS, coupled with the failure of an extensive extent-of-cause analysis, was an opportunity to approximate the rate of contamination. The film deposited on employee automobiles was not easily removed and not even high pressure car washes were totally effective at removing it. It is reasonable to assume that the dry weather conditions completely eliminated the possibility that any precipitation event could help cleanse the insulators. Any contamination accumulation would not be removed and would actually act to seed and accelerate the contamination accumulation process.

The licensee has completed, and planned, numerous corrective and preventive actions as a result of the root cause analysis. Corrective and preventive actions taken to date include: (1) a thorough cleaning of all insulators in Transformer Yards 1 and 2 and repair and testing as appropriate; (2) the repair of the cooling tower drift eliminators according to the vender’s recommendations; (3) a review of other potential effects on the plant from the cooling tower drift; (4) establishing a performance monitoring program for the 230 kV insulators (the installation and testing of dummy insulators at various locations around the site to monitor for contamination buildup); and (5) dissemination of the operating experience to the industry.

Preventive measures planned include: (1) establishing PM for the cooling towers; (2) establishing PM for cleaning the 230 kV line insulators; and (3) evaluating protective coatings that can be applied to insulators to resist contamination buildup.

.3 Root Causes for Operator and Plant Response to Scram

No findings of significance were identified. SERT Team 2 used several commercially available root cause techniques to determine root causes where necessary. These techniques included the Institute of Nuclear Power Operations (INPO) Human Performance Enhancement System, System Improvement’s TapRoot, and PII’s Organizational and Programmatic Diagnostics. Nuclear Management Manual EM-LI-118, “Root Cause Analysis Process,” Revision 0, was also used by the SERT. The team determined the root causes for the areas of RPV level and pressure control, and main condenser operational events. These issues are covered in detail in Sections 3.3 and 3.4. The inspectors have determined that the licensee’s root cause and corrective actions were adequate.

3.6 Industry Operating Experience and Potential Precursors (Charter Item 2)

a. Inspection Scope

The inspectors reviewed the industry operating experience the licensee gained through their investigation into the corona effects and insulator arcing experienced in the weeks leading up to the event on October 1, 2004. Interviews of licensee personnel, and reviews of material found, with the assistance of the NRC's Operating Experience Section, were conducted by the inspectors.

b. Findings and Observations

No findings of significance were identified. The inspectors concluded that the licensee did adequately search and review operating experience for assistance with the corona effects that were observed on site. The licensee identified a small number of operating experience documents that were similar to the condition at RBS prior to the events on October 1, 2004. The licensee also communicated with the local transmission company and EPRI concerning the insulator arcing observed on the 230 kV lines. Information gathered from these communications varied widely as to when the licensee should take corrective action. The corona effect intensity was quantitatively determined by the percentage of the insulator length that was experiencing arcing. The licensee set trigger points for action based upon their discussions with these offsite sources. The subject of corona and its effects are widely observed, and there appears to be varying opinions as to at what point it becomes an operational concern.

The licensee had no experience in cleaning insulators at power and contracted out the cleaning. According to system engineers, the insulators at RBS had not been cleaned since installed and placed into operation. During the licensees' operational experience search, they identified and communicated with two plants that had some experience with cleaning high voltage insulators. These cleaning options were evaluated and, based upon the switchyard configuration and the desire to keep the line energized, the option of cleaning with dry ice (CO_2) was selected.

The inspectors also noted that the licensee did not identify any previous RBS history of corona or any previous events or conditions related to insulator arcing. This was the first time since plant operations began that any insulation arcing had been identified.

3.7 Common Cause and Generic Issues (Charter Items 7 and 8)

a. Inspection Scope

The inspection team reviewed the event as a whole and the root cause of the loss of RSS Line 1 and the main generator output line. The inspectors also interviewed licensee personnel and Texas Utilities (TXU) transmission personnel and reviewed industry operating experience and NRC Information Notices. Previous plant scrams were also reviewed by the inspectors.

b. Findings and Observations

Common Cause

The inspectors determined that the ground faults that resulted in the loss of RSS Line 1 and the main generator output line (and led to a reactor scram) were caused by the salt contamination deposited on the high voltage insulators. The source of the salt contamination was the degraded recirculating water cooling tower drift eliminators. The plant had not experienced the high number cooling tower drift eliminator failures (17 total) in its operating history. Although the licensee was aware of the degraded cooling towers, the actual number of drift eliminator failures was not discovered until after the event on October 1, 2004.

The insulator degradation mechanism at RBS was the product of two conditions: (1) availability of salt laden material, and (2) weather conditions. The degraded cooling tower drift eliminators supplied the salt laden material for deposition on the insulators. The weather acted to both promote salt contamination buildup (wind direction and dry conditions) and to trigger the ground faults (foggy conditions). The excessive moisture in the cooling tower effluent was carried by wind currents over the plant and into Transformer Yard 1. On a significantly lower number of occasions, the wind took the cooling tower effluent into Transformer Yard 2. Transformer Yard 2 is approximately 500 feet further south-southwest of Transformer Yard 1, and subsequently further away from the degraded cooling towers. Once the contamination was to the point of possibly causing insulator failure, moisture was the triggering mechanism for ground faults. The heavy fog and cooling tower effluent that settled over Transformer Yard 1 on October 1, 2004, caused the chain of events that day.

The inspectors determined that, although Transformer Yard 2 and RSS Line 2 (Division II offsite power) were affected by the salt contamination, the magnitude was considerably less than Transformer Yard 1. The RSS Line 1 and the main generator output lines in Transformer Yard 1 would be at significantly greater risk of ground faults and would fail prior to an RSS Line 2 failure. Therefore, it would be highly unlikely that both lines of offsite power would be lost to the same type of insulator failure. The inspectors determined that no common cause for insulator failures existed.

Generic Issues

Nuclear plants that are located on a coast or that have had cooling tower problems for their entire operating life are knowledgeable about insulator contamination, corona effects, and the specific conditions surrounding insulator failures. Many factors and variables are involved concerning the issue of insulator contamination and failure. As cooling towers age and are tasked with dissipating greater heat loads, the probability for degradation increases. Plants, such as RBS that have no history of these types of problems, can experience insulator contamination and not be fully aware of the causes, signs, corrective actions, or consequences. The inspectors were unable to locate any NRC operating experience concerning corona effects, although there is some information on insulator failures caused by contamination (salt buildup).

The inspection team concluded that similar failures, conditions, and events could occur in the nuclear industry, specifically at plants with cooling towers. All plants that have cooling towers are susceptible, even if they have no records of this type of insulation contamination and failure in the past.

4.0 OTHER ACTIVITIES

4OA2 Problem Identification and Resolution

Section 3.5.1 describes a finding for failing to perform a proper extent-of-condition determination that led to an initiating event and prompt corrective action following a self-imposed limit for insulator arcing.

4OA4 Crosscutting Aspects of Findings

Section 3.4.1 describes a finding for a failure to implement a Technical Specification required AOP for main condenser vacuum. Not only were there human performance aspects to this failure, but the licensee had a previous opportunity to identify the procedural inadequacy one month earlier and failed to place the issue into their corrective action program.

4OA6 Meetings, Including Exit

On December 16, 2004, the team presented the preliminary inspection results to Mr. P. Hinnenkamp and other members of his staff at the RBS. Mr. Hinnenkamp acknowledged the team's findings. The team ensured that proprietary information reviewed, if any, was returned to the licensee.

On January 14, 2005, the team re-exited to relay the results of a Phase 3 significance determination for the only outstanding finding to Mr. R. King and other members of the licensee staff via telephone. Mr. King acknowledged the final team's findings.

4OA7 Licensee-Identified Violation

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

- 10 CFR 55.46.c states in part, "A plant-referenced simulator used for the administration of the operating test or to meet experience requirements . . . must demonstrate expected plant response to operator input and to normal, transient, and accident conditions to which the simulator has been designed to respond . . . ." RBS experienced two reactor scrams (August 15 and October 1, 2004) in which actual plant SRV manipulations caused shrink, swell, and level indications that were different than what was modeled in the simulator. After some investigation by the licensee, it was determined that level variations in the simulator were 6-8 inches different than in the actual plant. Considering that RPV level is normally maintained between Level 8 (51 inches) and Level 3 (9.7 inches), 6-8 inches constitutes approximately a 15-20 percent difference than actual plant condition. Coupled with the fact that most of the operators on shift during the events had never actually manipulated SRVs in the plant, this simulator fidelity deficiency could have an impact on operator performance. This issue was documented in the licensee's corrective action program in Condition Report CR-RBS-2004-2334. This violation is of very low safety significance because it did not involve an exam or operating test, but did involve a simulator fidelity issue which impacted operator actions and resulted in negative training.

ATTACHMENTS: SUPPLEMENTAL INFORMATION
SPECIAL INSPECTION CHARTER
SEQUENCE OF EVENTS

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

P. Hinnenkamp, Vise President - Operations
Tom Bagbey, Electrical Maintenance Supervisor
Russell Beauchamp, Oversight
Louis Brown, 3rd Reactor Operator
Joey Clark, System Operations Manager
David Clymer, Control Room Supervisor and Shift Technical Assistant
Ronnie Cole, Engineering Supervisor
Faliesha Corley, Engineering Supervisor of Fix It Now (FIN) Team
Dale Dawson, Shift Manager
Ron Findish, Plant Program Engineer
Steve Flore, Reactor Operator (Tagging Official)
John Fralick, Senior Operations Instructor
Thomas Hunt, PSA Engineer
Gary Huston, Assistant Ops Manager Oversight
Rick King, Director of NSA (OSRC Chairman)
Glen Krause, Control Room Supervisor
John Magher, Reactor Engineering
Joe Malara, Director of Engineering
Glen Miller, RCIC and CRD System Engineer
Jerry Parker, System Engineer (FIN Team)
Robbie Peek, Control Room Supervisor
Mike Peno, System Engineer
Art Roshto, Electrical Superintendent
James Schlesinger, Design Engineering Supervisor
Eric Stone, RO At-The-Controls
Bill Stuart, RCIC System Engineer
David Young, CRS-STA

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed

05000458/20040012-01	NCV	Technical Specification 5.4.1.a violation for failure to implement a required procedure for loss of main condenser vacuum (Section 3.4)

05000458/2004012-02 FIN Failure to maintain circulating water cooling tower drift eliminators (Section 3.5)

Closed

None

LIST OF DOCUMENTS REVIEWED

Condition Reports

CR-RBS-2003-0886	CR-RBS-2003-0890	CR-RBS-2003-1125	CR-RBS-2003-1275
CR-RBS-2003-1782	CR-RBS-2003-1935	CR-RBS-2003-1944	CR-RBS-2003-1973
CR-RBS-2003-2665	CR-RBS-2003-2668	CR-RBS-2003-2919	CR-RBS-2003-3604
CR-RBS-2004-0022	CR-RBS-2004-0078	CR-RBS-2004-0659	CR-RBS-2004-1038
CR-RBS-2004-1148	CR-RBS-2004-1268	CR-RBS-2004-1500	CR-RBS-2004-1770
CR-RBS-2004-1822	CR-RBS-2004-2049	CR-RBS-2004-2146	CR-RBS-2004-2333
CR-RBS-2004-2334	CR-RBS-2004-2361	CR-RBS-2004-2362	CR-RBS-2004-2408
CR-RBS-2004-2474	CR-RBS-2004-2579	CR-RBS-2004-2624	CR-RBS-2004-2654
CR-RBS-2004-2694	CR-RBS-2004-2717	CR-RBS-2004-2749	CR-RBS-2004-2796
CR-RBS-2004-2838	CR-RBS-2004-2839	CR-RBS-2004-2841	CR-RBS-2004-2842
CR-RBS-2004-2844	CR-RBS-2004-2847	CR-RBS-2004-2848	CR-RBS-2004-2851
CR-RBS-2004-2852	CR-RBS-2004-2854	CR-RBS-2004-2856	CR-RBS-2004-2859
CR-RBS-2004-2861	CR-RBS-2004-2862	CR-RBS-2004-2863	CR-RBS-2004-2866
CR-RBS-2004-2875	CR-RBS-2004-2879	CR-RBS-2004-2880	CR-RBS-2004-2904
CR-RBS-2004-2906	CR-RBS-2004-3049		

Procedures

Abnormal Operating Procedure AOP-0010
Abnormal Operating Procedure AOP-0001
Abnormal Operating Procedure AOP-0002
Abnormal Operating Procedure AOP-0003
Abnormal Operating Procedure AOP-0005, Revision 15
Abnormal Operating Procedure AOP-0006

Abnormal Operating Procedure AOP-0053
Abnormal Operating Procedure AOP-0061, Revision 3
Alarm Response Procedure ARP-P680-07, Revision 18
Emergency Operating Procedure EOP-0002
Emergency Operating Procedure EOP-0005
General Maintenance Procedure GMP-0099, Revision 4
General Operating Procedure GOP-0003, Revision15
Nuclear Management Manual EN-LI-111, Revision 1
Surveillance Test Procedure, STP-051-4507, Revision 11

Drawings

CBD-VBN06
CBD-VBN06A
Pump Curve T-3307, 12-17-79
828E531AA, Sheet 1, 2, 2A, 3, 7, and 9
12210-EP-1B-Sheet 2
EA-040C, Rev 5
EE-001AC, Rev 27
12210-EE-30A, Rev 10
EE-30C, Rev 4
EP-1A,1D, and 1G
EE-001ZB
EE-30A
12210-EE-30C, Rev 4
12210-EE-30F-2

PID-02-01A, Rev 20
PID-02-01B, Rev 40
PID-02-01C, Rev 10
PID-04-01A, Rev 28
PID-04-02A, Rev 14
PID-04-02A, Rev 11
PID-04-02C, Rev 10
PID-04-02D, Rev 10
PID-04-02G, Rev 10
PID-04-02H, Rev 15
PID-06-01A, Rev 17
PID-06-01B, Rev 27
PID-09-01A, Rev 14
PID-09-01B, Rev 18
PID-26-03A, Rev 30
PID-26-03B, Rev 18
PID-27-06A, Rev 40

Other Documents

Fuel Integrity Monitoring Committee (FIM) Meeting Minutes, October 4, 2004
Procedure Action Request for AOP-0005
Preventative Maintenance PM: RBS_Control Relay-Agastat GP/EGP (Rev 1, 7/04)
Root Cause Analysis Report, “Failure of EHC Tubing in the Turbine Building,” May 2003
Root Cause Analysis Report, “Reactor Scram of 9/22/03,” September 2003
Root Cause Analysis Report, Fancy Point Slow Breaker Operations Resulting in River Bend Station Plant Scram-FO 04-01,” September 2004
Operations Section Procedure OSP-0053, Revision 01A
Simulator Discrepancy Report DR-04-0126
Simulator Discrepancy Report DR-04-0140
Turbine Building Radiation Survey Maps
GE Nuclear Energy SIL No. 310, “C11 CRD Hydraulic Control System,” October 1979
GE Nuclear Energy SIL No. 463, “Process Instrument Noise,” Revision 1, July 1991

Work Order Package 36425-01, and 36425-02
Work Order Package 50087-01

LIST OF ACRONYMS

AOP	abnormal operating procedure
ATC	at-the-controls operator
CFR	*Code of Federal Regulations*
CRS	control room supervisor
EPRI	Electric Power Research Institute
ERIS	emergency response information system
ICCDP	incremental conditional core damage probability
INPO	Institute of Nuclear Power Operations
KT	kepner-tregoe
MSIV	main steam isolation valve
NCV	noncited violation
NRC	Nuclear Regulatory Commission
ODMI	operational decision management issue
OSRC	operational safety review comittee
PCS	power conversion system
PM	preventive maintenance
RBS	River Bend Station
RCIC	reactor core isolation cooling
RPV	reactor pressure vessel
RSS	reserve station service line
SERT	significant event response team
SOP	system operating procedure
SPAR	standard plant analysis risk
SRA	senior risk analyst

SRV	safety relief valve
TXU	Texas Utilities

SPECIAL INSPECTION CHARTER

October 4, 2004

MEMORANDUM TO: Alfred A. Sanchez, Jr.
Resident Inspector, Comanche Peak Steam Electric Station

FROM: Arthur T. Howell III, Director **/RA/ by AVegel for**
Division of Reactor Projects

SUBJECT: CHARTER FOR THE SPECIAL INSPECTION TEAM AT RIVER BEND STATION REACTOR SCRAM WITH COMPLICATIONS

A. Basis

On October 1, 2004, at approximately 7:19 a.m. (CDT), a fault occurred on Reserve Station Service (RSS) Line #1, causing a loss of the Division I emergency bus which was being supplied from off-site power through RSS1. The Division I emergency diesel generator started and loaded as designed.

At 7:30 a.m., a fault on the main transformer output line caused a generator lock-out, turbine trip, and subsequent reactor scram. The main steam isolation valves were closed by the operators due to lowering main condenser vacuum and lowering main steam line pressure. The reactor was stabilized using the High Pressure Core Spray system and Safety Relief Valves to maintain reactor level and pressure control.

The electrical faults resulted in a loss of main feedwater and condensate systems ability to provide makeup water to the reactor. Additionally, the Reactor Core Isolation Cooling system experienced a steam supply isolation in conjunction with the reactor scram.

In accordance with Management Directive 8.3, “NRC Incident Investigation Program,” the occurrence of multiple failures in systems used to mitigate an actual event in conjunction with the conditional core damage probability calculated utilizing conditions known to exist during the event comprise sufficient justification to initiate a special inspection.

B. Scope

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

1. Develop a complete sequence of events related to the fault on the RSS Line #1 and the subsequent fault on the main transformer, which lead to the reactor scram on October 1, 2004.

Evaluate pertinent industry operating experience and potential precursors to the condition, including the effectiveness of any action taken in response to the operating experience.

2. Review the adequacy of the post-trip review. Include in this review the thoroughness of the licensee’s assessment of the event and whether potential complications on the plant systems (i.e., extent of conditions) were properly considered, the quality and adequacy of the operability evaluations, and the comprehensiveness and appropriateness of the immediate and long-term corrective actions.

3. Review the licensee's root cause determination for independence, completeness, and accuracy, including the risk analysis of the event.

4. Evaluate the adequacy of the operator response to the transient.

5. Review all pertinent equipment performance, and system responses.

6. Evaluate and determine the common-cause aspects of the event.

7. Review the event to determine whether there are any generic issues.

C. <u>Team Members</u>

- Alfred A. Sanchez, Jr., Resident Inspector and Team Leader
- James Drake, Operations Engineer
- Peter Alter, Senior Resident Inspector to assist as needed

D. <u>Guidance</u>

Inspection Procedure 93812, "Special Inspection," dated July 7, 2003, provides additional guidance to be used by the Special Inspection Team.

This memorandum designates you as the Special Inspection Team leader. Your duties will be as described in Inspection Procedure 93812. The team composition will consist of yourself and Mr. James Drake, Operations Inspector, Region IV. Mr. Peter Alter, the River Bend Station Senior Resident Inspector, will provide assistance as needed during the inspection. During performance of the Special Inspection, the designated team member is separated from normal duties and reports directly to you. The team is to emphasize fact-finding in its review of the circumstances surrounding the event. Safety concerns identified that are not directly related to the event should be reported to the Region IV office for appropriate action.

The Team will report to the site, conduct an entrance, and begin inspection on October 4, 2004. Tentatively, the inspection should be completed by the close of business on October 8, 2004. A formal exit will be scheduled following completion of the on-site inspection. A report documenting the results of the inspection will be issued within 30 days of the completion of the inspection. While the team is onsite, you will provide daily status briefings to Region IV management.

This Charter may be modified should the team develop significant new information that warrants review. Should you have any questions concerning this Charter, contact Mr. David Graves at (817) 860-8141.

cc via E-mail:
B. Mallett
T. Gwynn
D. Chamberlain
A. Howell
A. Vegel
A. Gody
D. Powers
R. Kopriva
D. Loveless
M. Runyan
R. Bywater
M. Mitchell, OEDO
H. Berkow, NRR
R. Gramm, NRR
M. Webb, NRR

SEQUENCE OF EVENTS

Time	Events/Comments
0718:00	RSS 1 tripped. AOP-0010, Loss of one RPS Bus. Division 1 Diesel Generator started and is carrying ENS-SWG01A
0722:00	Reset Division 1 Alternate EPA breakers, swapped RPS-A to Alternate power, rest NIs, reset Div 1 half scram, reestablished Instrument Air Supply (IAS) and Component Cooling Water (CCP) to containment per AOP-0010
0729:40	B21-F051C and F051D SRVs **opened** on Low-Low Set to control reactor pressure
0729:51	B21-F051C and F051D SRVs **closed** on Low-Low Set to control reactor pressure
0730:00	Received a reactor scram due to a main generator/turbine trip. Entered EOP-1 on Reactor Level 3 and High reactor pressure. Also entered AOP-0001, 0002, 0003,0005,0006, 0053 Trip of the main generator and the RSS 1 line resulted in the loss of NPS-1A, NNS-2A–Major equipment lost were CNM-P1A, P1C; FWS-P1A; CWS-P1A, P1C; and Reactor Recirc Pump A
0731:00	Lost high pressure feedwater: Feedwater Pump "A" tripped on loss of power Condensate Pump "A" tripped on loss of power Condensate Pump "B" tripped on loss of power Feedwater Pump "B" tripped on low suction pressure Feedwater Pump "C" tripped on low suction pressure Condensate Pump "C" continues to run Found RCIC isolated from Division II isolation signal–Due to a Main Steam Supply High Differential Pressure. Direction given to reset the isolation and commence RCIC system warmup
0732:15	Initiated HPCS due to loss of FWS on low suction pressure, Level 3 Division III EDG started (Did not load due to power available on E22-S004.) CRS gives LEVEL CONTROL to operator who initiated HPCS with a level band of 10"-51." HPCS was initiated when level was approximately -17" and level was restored above +25" and the HPCS injection valve was manually overriden closed (via operator interview)

0734-0735	CRS widens level band to -20" to 51" Closed outboard MSIVs due to lowering vacuum pressure
0748:48	Reset Div II RCIC isolation
0749:00	Reset reactor scram per AOP-0001
0751:00	Swapped SCI-TRS1 to NPS"B" for control room indications and logic for feed pump start (Restored power to Feed pump min flow valves)
0755:29	Started FWS-1CP
0758:41	Closed Inboard MSIVs due to lowering of Main Condenser Vacuum (at least 8.5" of vacuum remained in Main Condenser)
0800:36	Reactor pressure is maintained via SRV operation (Low-Low Set) -Automatic Action (pressure band of 500 to 1090 psig per EOP-0001 is assigned) Level 8 and FWS-1CP trip during SRV operation
0801:32	Suppression Pool Level High- Entered EOP-0002 CRS re-assigns Level Control to ATC operator with a band of 10"-51"
0801 through 0806	SRV automatically open and close twice to maintain pressure (Low-Low Set)
0809	Attempted to restart FWS-P1B per SOP-0009 and would not start due to a sealed in trip signal (trip indication bulb was burned out at the console)
0810:33	SRV F051D was automatically opened for pressure control (Low-Low pressure set) and the control switch was subsequently taken to the open position to bring pressure to lower end of the control band (500 to 1090 psig)
0811	RCIC warm up in progress
0815:00	Received a Level 3 and RPS actuation due to SRV operation

0816:00	Began injecting with HPCS for level control SRV F051D was manually closed for pressure control Note: From interviews with the operators, the ATC operator noticed that a level 2 was coming, the SRV was closed and HPCS was initiated. Received a Level 2, Reactor Recirc pump B tripped on the Level 2, re-entered AOP-0003 for automatic isolations for Level 2 Started FWS-P1C
0817	Reactor water level is above Level 2
0819	Reactor water level is above Level 3
0820	Reset Reactor Scram HPCS injection was terminated
0824	Reactor Core Isolation Cooling (RCIC) is in standby
0830	Swapped HPCS suction valves to the suppression pool to prevent water addition to the suppression pool
0936	Level 8 and ½ scram received during SRV operation. Reset the ½ scram
0946	Bypassed Condenser Low Vacuum Isolations
0954	Main Condenser Indicates a positive pressure (and remains positive)
1013	Entered EOP-0002 for High Containment Temperature Secured ARC-P1A, B and the Iodine Filter Train due to water in the filter Started HVR-UC1A for containment temperature control
1030	Closed MSL Drains
1038	Level 3 received due to SRV operation Reset reactor scram due to level 3
1101	Received a Level 8, and a ½ scram
1104	Reset ½ scram
1220	Received a Level 8 during SRV operation

1223	Reset ½ scram
1231	Received a Level 8 during SRV operation, Rest ½ scram
1243	Received a Level 8 during SRV operation, Rest ½ scram
1307	Received a Level 8 during SRV operation, Rest ½ scram
1401	Level 3 received due to SRV operation Reset reactor scram due to level 3
1947	Received a Level 8 during SRV operation, Full reactor scram due to existing Division 2 ½ scram
1955	Reset the scram
2203	Cross-tied NJS-SWG3C/D to allow the closure of the CWS discharge MOVs on the out of service pumps
2335	Reactor is in Mode 4