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

May 19, 2004

James J. Sheppard, President and
Chief Executive Officer
STP Nuclear Operating Company
P.O. Box 289
Wadsworth, Texas 77483

SUBJECT: SOUTH TEXAS PROJECT ELECTRIC GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000498/2004002 AND 05000499/2004002

Dear Mr. Sheppard:

On April 7, 2004, the US Nuclear Regulatory Commission (NRC) completed an inspection at your South Texas Project Electric Generating Station, Units 1 and 2, facility. The enclosed integrated report documents the inspection findings, which were discussed on April 15, 2004, with you and members of your staff.

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

This report documents five findings of very low safety significance (Green), evaluated under the risk significance determination process (SDP), four of which 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 (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. In addition, one unresolved item having at least very low safety significance was identified. If you contest any NCVs 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, U.S. Nuclear Regulatory Commission Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington DC 20555-0001; and the NRC Resident Inspector at South Texas Project Electric Generating Station, Units 1 and 2, 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 made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

**/RA/**

William D. Johnson, Chief
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Dockets: 50-498
50-499
Licenses: NPF-76
NPF-80

Enclosure:
NRC Inspection Report 05000498/2004002 and 05000499/2004002
w/Attachment: Supplemental Information

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| 05/19/04 | 05/19/04 | 05/19/04 | 05/18/04 | 05/19/04 |

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| 05/19/04 | 05/19/04 | 05/19/04 | 05/19/ 04 | |

**ENCLOSURE**

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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|---|---|
| Dockets: | 50-498, 50-499 |
| Licenses: | NPF-76<br>NPF-80 |
| Report No: | 05000498/2004002<br>05000499/2004002 |
| Licensee: | STP Nuclear Operating Company |
| Facility: | South Texas Project Electric Generating Station, Units 1 and 2 |
| Location: | FM 521 - 8 miles west of Wadsworth<br>Wadsworth, Texas 77483 |
| Dates: | January 1 through April 7, 2004 |
| Inspectors: | J. Cruz, Senior Resident Inspector<br>G. Guerra, Resident Inspector<br>M. Shannon, Senior Health Physicist<br>B. Tharakan, Health Physicist<br>W. Sifre, Reactor Inspector<br>P. Elkmann, Emergency Preparedness Inspector<br>T. Farnholtz, Senior Project Engineer<br>A. Barrett, Project Engineer<br>N. O'Keefe, Senior Reactor Inspector<br>D. Stearns, Project Engineer |
| Approved By: | W. D. Johnson, Chief<br>Project Branch A<br>Division of Reactor Projects |

## CONTENTS

## SUMMARY OF FINDINGS

IR 05000498/2004002, 05000499/2004002; 01/01/04 - 04/07/04; South Texas Project Electric Generating Station; Units 1 & 2; personnel performance, operability evaluations, surveillance testing, ALARA planning and controls, PI&R, and Other.

This report covered a 3-month period of inspection by the resident inspectors and Region IV inspectors. Four Green noncited violations (NCVs), one Green finding and three unresolved items having at least very low safety significance were identified. The significance of most findings are 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. A finding was identified for the failure of reactor operators to appropriately respond to an event that resulted in a plant transient. On January 23, 2004, operators inappropriately responded to plant conditions which resulted in an event becoming more significant. Operators appropriately diagnosed the failure and operator response was clearly understood and communicated. However, operators inappropriately manipulated the steam generator level controls and did not control steam generator levels in the A and B steam generators. An automatic reactor trip occurred due to high steam generator level in the B steam generator.

  This issue was more than minor because it was similar to Example 4.b in Manual Chapter 0612, Appendix E, "Examples of Minor Issues," and it met the "not minor if" criteria, in that the error resulted in a plant transient. This issue affected the Initiating Events Cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions, in that operators inappropriately manipulated the steam generator level controls and did not control steam generator levels. A Phase 1 Significance Determination Process determined that the performance deficiency represented a finding of very low risk significance (Green) because it did not contribute to a primary or secondary loss of coolant accident, did not contribute to both the likelihood of a reactor trip and the likelihood that mitigating equipment or function will not be available, and did not increase the likelihood of a fire or internal/external flood. This finding also had crosscutting issues associated with human performance because personnel failed to adequately control steam generator levels due to misoperation of plant equipment (Section 1R14).

- Green. A noncited violation of 10 CFR Part 50 Appendix B, Criterion XVI, Corrective Action was identified for the failure to implement effective corrective action for inverter failures that occurred at the South Texas Project. The licensee had identified previous failures of the Class 1E 7.5 kV inverters as significant conditions adverse to quality. However, the licensee did not assure that the cause of the condition was determined and corrective actions were taken to preclude repetition.

Reliability of the inverters was reasonably within the licensee's ability to foresee and correct and these failures could have been prevented. The failure of the inverters resulted in additional significant events, including a plant transient. The Phase 1 significance determination process screening resulted in the need for a Phase 2 evaluation because the finding contributes to both the likelihood of a reactor trip and the likelihood that mitigating equipment will not be available. The Phase 2 evaluation resulted in a finding with a potential of greater than very low safety significance using the counting rule which then necessitated a Phase 3 analysis. Phase 3 analysis determined that the issue was of very low safety significance, with the dominant sequence being an inverter failure which leads to a reactor trip. Corrective actions included replacing the at fault aged ferro-resonant transformers in all the safety related Class 1E inverters. This finding had crosscutting issues associated with problem identification and resolution because personnel failed to correct degraded conditions (Section 4OA2.1).

Cornerstone: Mitigating Systems

- Green. A noncited violation of 10 CFR Part 50 Appendix B, Criterion XVI, Corrective Action, was identified for the failure to implement effective corrective action for previous main steam power operated relief valve failures that occurred at the South Texas Project. An adrift 3/8 inch piece of wiring insulation caused only an occasional interruption in the mating of the breaker contacts for the main steam power operated relief valve hydraulic motor. Earlier, on November 3, 2003, an identical failure occurred and at the time, the failure could not be reproduced in six trials. The licensee concluded that the power operated relief valve was functional following the troubleshooting effort on November 3 in all cases except in a seismic event. This was based on the assumption that the movable piece of insulation was in a harmless location during this time and that only a shaking of the breaker cubicle from either a seismic event or the shaking caused by racking the breaker in and out (which occurs during the testing) would move it to a location that could cause the observed malfunction. Corrective action for this condition included having the vendor address this issue by providing objective evidence of programmatic changes made to prevent reoccurrence. The licensee developed a procedure for the inspection of breaker starter contacts for foreign material prior to installation.

  The failure to identify the root cause of the hydraulic pump failure on November 3, 2003, was a performance deficiency. Therefore, main steam power operated relief Valve 1B was in a degraded condition from that time until December 19, 2003, when the breaker was replaced. Because the finding involved the potential loss of a risk-significant component, it did not meet the criteria in MC 0612, Appendices B and E, for categorization as a minor issue. A Senior Reactor Analyst concluded that during the exposure period, the hydraulic pump and, thus, the power operated relief valve would have operated successfully in response to any event that did not also produce a physical shaking of the breaker cubicle. This shaking could only result from a seismic event. The analyst evaluated the finding under the external events screening criteria on Page 3 of 3 of the Phase I screening worksheets in MC 0609, Appendix A. The relevant question on this page (#3) asks whether the finding involves a total loss of a safety function that contributes to external events initiated core damage sequences. This question can be answered "no" because three other power operated relief valves were available for use in a reactor coolant system cooldown. Therefore, the analyst determined that the finding screens as Green, very low risk significance under Phase 1 of the Significance Determination Process. This finding also had crosscutting issues associated with problem identification and resolution because personnel failed to correct degraded conditions (Section 4OA3.2).

Cornerstone: Barrier Integrity

- TBD. A violation of Technical Specification 6.8.1.a and Regulatory Guide 1.33, Appendix A was identified for an inadequate procedure that resulted in a letdown pressure relief valve opening during a letdown orifice swap. The chemical and volume control system is an interfacing system with the reactor coolant system. With the medium and large letdown orifices both open the letdown flow is 205 to 250 gpm. The letdown pressure relief valve has a flow rate of greater than 300 gpm. With the potential for this amount of flow to exit the reactor coolant system if letdown could not be isolated, the risk of the initiation event of an interfacing small loss of coolant accident and degradation of the reactor coolant system barrier integrity is increased.

  This finding is greater than minor because it had the actual impact of lifting a relief valve and therefore could be reasonably viewed as a precursor to a significant event. The inspectors performed a Phase 1 screening in accordance with Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." Because this finding affected both the initiating event and barrier cornerstone the Phase 1 screening passed to Phase 2. A RIV senior reactor analyst is performing a review of the Phase 2 evaluation. This finding is an unresolved item pending significance determination (Section 1R14).

- Green. The inspectors identified a noncited violation of Technical Specification 6.8.1 and a Regulatory Guide 1.33 required procedure. The violation involved a failure to establish an appropriate procedure for testing pressurizer pressure instrumentation. The inadequate procedure resulted in a pressurizer power-operated relief valve lifting while Unit 1 was at 100 percent power.

  This finding is greater than minor because it was similar to Example 4.b in NRC Inspection Manual Chapter 0612, Appendix E, "Example of Minor Issues," and it met the "not minor if" criteria in that the error resulted in a plant transient. The performance deficiency was determined to represent a finding of very low safety significance. This was based on a Phase 3 analysis performed by a Senior Reactor Analyst in Region IV. The major factor in this determination was the very small change in core damage frequency as a result of this performance deficiency (Section 4OA5).

Cornerstone: Occupational Radiation Safety

- Green. The inspectors identified three examples of a noncited violation of Technical Specification 6.8.1(a) because the licensee failed to follow procedural requirements. Plant General Procedure 0PGP03-ZA-0010, required station personnel to stop and resolve an issue when the performance of a procedure step would not have achieved the desired result. During the initial setup and leak check of a reusable waste container, the operator was required to ensure that Valve 1(2)-WS-0077 was open. However, the procedure incorrectly referred to Valve 1(2)-WS-0077 instead of the correct Valve 1(2)-WS-0079. Ensuring Valve 1(2)-WS-0077 was open would not have achieved the desired result. On April 20, July 8, and July 20, 2003, the licensee failed to stop and resolve the error with the reference to the incorrect valve.

  The failure to follow procedural requirements are three examples of a performance deficiency. The finding is greater than minor because it could be reasonably viewed as a precursor to a significant event and it affected the Occupational Radiation Safety cornerstone objective, which is to ensure adequate protection of worker health and safety from exposure to radiation. The finding was associated with the cornerstone attribute of Program and Process. When processed through the Occupational Radiation Safety Significance Determination Process, the finding was found to have very low safety significance because it was not associated with ALARA planning or work controls, there was no overexposure or a substantial potential for overexposure, and the ability to assess dose was not compromised (Section 2OS2).

B. Licensee-Identified Violations

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

# REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent power. On January 23 the unit experienced an automatic reactor trip due to the failure of Class 1E 7.5 kV Inverter 1201. The unit was restarted on January 26 and operated at essentially 100 percent power for the remainder of the inspection period.

Unit 2 operated at essentially 100 percent power throughout the inspection period. On March 31 the unit shut down for a scheduled refueling outage and was defueling at the end of the inspection period.

## 1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

### 1R01 Adverse Weather Protection (71111.01, 71153)

a. Inspection Scope

On April 6 the inspectors responded to the site and observed the licensee's response to adverse weather for tornado warnings. The inspectors reviewed Plant General Procedure 0PGP03-ZV-0001, "Severe Weather Plan," Revision 10.

b. Findings

No findings of significance were identified.

### 1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors conducted partial walkdowns of the following four risk-significant systems to verify that they were in their proper standby alignment as defined by system operating procedures and system drawings. During the walkdowns, inspectors examined system components for materiel conditions that could degrade system performance. In addition, the inspectors evaluated the effectiveness of the licensee's problem identification and resolution program in resolving issues which could increase event initiation frequency or impact mitigating system availability.

- On January 7 the inspectors verified the condition of the Unit 2 Train C emergency diesel generator. This walkdown was performed while the Train B emergency diesel generator was out of service for repair during an extended allowed outage. The inspectors compared system equipment and control board lineups to Plant Operating Procedure 0POP02-DG-0003, "Emergency Diesel Generator 23," Revision 39.

- On February 4 the inspectors performed a partial system walkdown on the Unit 1 rod control system. No maintenance activities were being conducted at the time of the walkdown, and there are no alternate trains. The inspectors visually observed the condition of the electrical equipment. The inspectors also held discussions with the responsible system engineer on the health of the system. The control board lineup was also inspected. The inspectors reviewed Plant Operating Procedure 0POP02-RS-0001, "Rod Control," Revision 16.

- On February 11 the inspectors performed a partial system walkdown on the Unit 2 reactor makeup water system. No maintenance activities were being conducted at the time of the walkdown, and there are no alternate trains. The inspectors also held discussions with the responsible system engineer on the health of the system. The inspectors compared system equipment and control board lineups to Plant Operating Procedure 0POP02-RM-0001, "Reactor Makeup Water System Operations," Revision 7.

- On March 31 the inspectors performed a partial system walkdown on the Unit 1 instrument/service air compressor and distribution system. No maintenance activities were being conducted at the time of the walkdown. The inspectors compared system equipment and valve alinement to Piping and Instrumentation Diagram (P&ID) 8Q119F00048 Sheets 1 and 2.

b. Findings

No findings of significance were identified

1R05 Fire Protection (71111.05)

.1 Fire Area Tours

a. Inspection Scope

The inspectors toured six plant areas to assess the licensee's control of transient combustible materials, the material condition and lineup of fire detection and suppression systems, and the material condition of manual fire equipment and passive fire barriers. The licensee's fire preplans and fire hazards analysis report were used to identify important plant equipment, fire loading, detection and suppression equipment locations, and planned actions to respond to a fire in each of the plant areas selected. Compensatory measures for degraded equipment were evaluated for effectiveness. The following plant areas were inspected:

- Unit 2 Train C switchgear and rod drive power supply rooms on January 7 (Fire Zones 052 and 056)

- Unit 1 Train B essential cooling water pump rooms on January 13 (Fire Zone 601)

- Unit 1 rod control and motor generator set rooms on February 4 (Fire Zones 54 and 56)

- Unit 2 refueling water storage tank and reactor makeup water storage tank rooms on February 11 (Fire Zones 103 and 104)

- Unit 1 inspection of nine penetration seals found with filler material thought to have been removed on March 4 (CR 04-3016)

- Unit 2 containment during the outage on April 2 (Fire Area 63)

b. Findings

No findings of significance were identified.

.2 Annual Fire Drill

a. Inspection Scope

On February 25, 2004, the inspectors observed a fire brigade drill staged at the Unit 1 standby transformer to evaluate the readiness of the fire brigade to fight fires. The inspectors reviewed the strategies and information in Fire Pre-plan OSBX99-FP-0750, "Fire Preplan for the Standby Transformer," Revision 0, to verify that it was consistent with the fire protection design features, fire area boundaries, and combustible loading assumptions shown in the fire protection plan. The inspectors observed the fire brigade members: (1) donning protective clothing, (2) selecting turnout gear, (3) entering the fire zone, and (4) communicating with the control room staff. The inspectors observed the fire fighting equipment brought to the fire scene to evaluate whether sufficient equipment was available for the simulated fire. The inspectors also observed fire fighting directions and radio communications between the brigade leader, brigade members, and the control room. Additionally, the inspectors attended the post drill critique.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

During the week of March 1, 2004, the inspectors verified that the licensee’s flooding mitigation plans and equipment were consistent with the licensee’s design requirements and risk-analysis assumptions in the Updated Final Safety Analysis Report. The inspection included a review of flood analysis documentation and calculations to determine areas susceptible to flooding from internal sources. A walkdown of the Unit 2 electrical auxiliary building 10' elevation was conducted and included the Train A

Class 1E switchgear and auxiliary shutdown panel rooms. The inspectors assessed the adequacy of flood protection measures regarding a postulated flood and verified that the mitigating systems defined in the flood analysis were in place and functional.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On February 3 the inspectors assessed Crew 1A during licensed operator simulator requalification training. The inspectors observed two control room simulator scenarios that included a faulted steam generator and a small loss of coolant accident. The inspectors observed the performance of the operator crew for clarity and formality of communications, the correct use of procedures, performance of high risk operator actions, monitoring of critical safety functions, and the oversight and direction provided by the shift supervisor. The inspectors observed the operators' use of emergency action levels, reviewed the scenario sequence and objectives, and discussed the crew's performance with training instructors.

b. Findings

No findings of significance were identified.

1R12 Maintenance Implementation (71111.12)

a. Inspection Scope

The inspectors independently verified that licensee personnel properly implemented 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," for the following equipment performance problems:

- (Common) History of Qualified Display Processing System power supply failures (CR 03-18137, 03-18098, and 02-4662)
- (Unit1) Train A 4160 volt bus deenergized during ESF load sequencer maintenance on January 18 (CR 04-965)

The inspectors reviewed whether the structures, systems, or components were properly characterized in the scope of the Maintenance Rule Program and whether the failure or performance problem was properly characterized. In addition, the inspectors assessed the appropriateness of the established performance criteria. The inspectors independently verified that the corrective actions and responses implemented were appropriate and adequate. Discussions with the responsible system engineer were also held.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors assessed whether the performance of risk assessments for selected planned and emergent maintenance activities was in accordance with 10 CFR 50.65(a)(4). The inspectors assessed the completeness and accuracy of the information considered in the risk assessments and compared the actions taken to manage the resultant risk with the requirements of the licensee's Configuration Risk Management Program. The inspectors reviewed these assessed risk configurations against actual plant conditions and any in-progress evolutions or external events to verify that the assessments were accurate, complete, and appropriate for the conditions. In addition, the inspectors walked down the control room and plant areas to verify that compensatory measures identified by the risk assessments were appropriately performed. The inspectors reviewed the following seven activities:

- Unit 2 medium risk work on reheater drip tank dump valve control system equipment during the Emergency Diesel Generator 22 extended allowed outage on January 2 and 6 (Work Authorization Number (WAN) 265401, Condition Record (CR) 03-18552)

- Unit 1 risk assessment regarding continued operations with evidence of age related degradation of the ferro-resonant transformer installed in the Class 1E 7.5 kV Inverter 1204 prior to replacement on February 6 (CR 04-1238)

- Unit 1 cumulative effect of online maintenance during a Train A systems work week on February 19

- Unit 2 work on 2B hydrogen recombiner identified as high risk during a Train C work week with the on going Emergency Diesel Generator 22 extended allowed outage on March 8 (WAN 248137)

- Unit 1 high risk work conducted to address increased thermal loads at the spade lug connections of the trim capacitors in the Class 1E 7.5 kV Inverters 1201 and 1202 on March 19 (WANs 271144 and 271171)

- Unit 2 restoration of essential cooling water Train B during Emergency Diesel Generator 22 extended allowed outage and Notice of Enforcement Discretion for control room envelope HVAC on March 24 (CR 03-18159)

- Unit 1 high risk work conducted to address failures in the iso-phase bus duct cooling control circuit, failure of the cooling fans would require a fast load reject on April 4 (WAN 271174)

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions (71111.14, 71153)

a. Inspection Scope

The inspectors observed three nonroutine evolutions described below to verify that they were conducted in accordance with licensee procedures and Technical Specification requirements. The inspectors observed personnel performance in the control room and in the field.

- Unit 1 letdown orifice swap results in letdown relief valve lifting on January 21
- Unit 1 automatic reactor trip due to failure of Class 1E 7.5 kV Inverter 1201 on January 23
- Unit 1 restart activities after an automatic reactor trip on January 26

b. Findings

.1 Inadequate Procedure Results in Relief Valve Opening

Introduction. A violation of Technical Specification 6.8.1.a and Regulatory Guide 1.33, Appendix A was identified for an inadequate procedure that resulted in a letdown pressure relief valve opening during a letdown orifice swap. This issue is an unresolved item pending significance determination.

Description. In order to reduce the risk of letdown isolation during a Train A emergency safety features (ESF) sequencer postmaintenance test, it was decided by the control room to place the “C” powered letdown orifice in service. The plant has three letdown orifices in the chemical and volume control system. The operators used Plant Operations Procedure 0POP03-CV-0004, “Chemical and Volume Control System,” Revision 34, to perform the evolution. Operators established that, to account for the difference in valve stroke times and to ensure that letdown would not be isolated, a full open indication on the middle sized orifice was needed before the large orifice was taken to close. This was believed to meet the intent of the procedure. The procedure outlined the following steps:

11.5 PERFORM the following simultaneously:

11.5.1 Open the letdown orifice isolation valve selected to be placed in service.

11.5.2 Close the letdown orifice isolation valve selected to be secured.

While the medium size orifice was going open, system pressure began to rise and operators attempted to control pressure using Pressure Control Valve PCV-0135. Pressure Control Valve PCV-0135 was not adjusted appropriately to compensate for its slow response. The valve response was slow and pressure in the system lifted the letdown pressure relief valve (600 psig lift point). As soon as the medium size orifice indicated full open, the large orifice was closed and the system stabilized. Alternatively, the operators could have used other sections of this procedure to accomplish this task due to the concern of letdown isolation.

Corrective actions for this event included enhancing the above procedure by adding notes and precautions and holding lessons learned sessions with operators.

Analysis. This finding is greater than minor because it had the actual impact of lifting a relief valve and therefore could be reasonably viewed as a precursor to a significant event. The chemical and volume control system is an interfacing system with the reactor coolant system. With the medium and large orifices both open the letdown flow is between 205-250 gpm. The relief valve has a flow rate of greater than 300 gpm. With the potential for this amount of flow to exit the reactor coolant system if letdown could not be isolated, the risk of the initiation event of an interfacing small loss of coolant accident and degrading the reactor coolant system barrier integrity is increased. The inspectors performed a Phase 1 screening in accordance with Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." Because this finding affected both the initiating event and barrier integrity cornerstone the Phase 1 screening passed to Phase 2. The Phase 2 evaluation is under review.

Enforcement. Technical Specification 6.8.1.a requires that procedures be established, implemented, and maintained covering the applicable procedures in Appendix A of Regulatory Guide 1.33. Appendix A, Item 3.n, requires procedures be maintained for the chemical and volume control system. Plant Operations Procedure 0POP03-CV-0004, "Chemical and Volume Control System," Revision 34, was not properly maintained in that it was inadequate in that the guidance it provided allowed the letdown relief valve to open. The opening of the letdown relief valve increased the risk of an initiating event of an interfacing system small loss of coolant accident and degraded the reactor coolant system barrier integrity. This finding was entered into the licensee's Corrective Action Program as CR 04-1143. This finding is an unresolved item pending significance determination. URI 05000498/2004-002-01, Inadequate Procedure Results in Relief Valve Opening.

.2 Operators Failed to Control Steam Generator Levels Upon Failure of Inverter 1201

Introduction. A Green finding was identified for the failure of reactor operators to appropriately respond to an event resulting in a plant transient. An automatic reactor trip was caused, in part, because operators did not control the rise in steam generator levels.

Description. The initiating event that led to the Unit 1 trip was the failure of a ferro-resonant transformer in a Class 1E 7.5 kV Inverter 1201 which caused a loss of power to distribution panel DP1201 on January 23, 2004. (See Section 4OA2 for more information on Class 1E 7.5 kV inverter failures). The loss of power to DP1201 caused associated steam generator level indications to fail low and feedwater demand to increase to 100 percent. Operators appropriately diagnosed the failure and operator response was clearly understood and communicated. However, operators inappropriately manipulated the steam generator level controls and did not control steam generator levels in the A and B steam generators. An automatic reactor trip occurred due to high steam generator level in the B steam generator.

Analysis. The inspectors determined that the finding is a performance deficiency because corrective action for past similar events included specific training for responding to the loss of instrumentation power distribution panels. This finding was more than minor because it was similar to Example 4.b in Manual Chapter 0612, Appendix E, “Examples of Minor Issues,” and it met the “not minor if” criteria, in that the error resulted in a plant transient. This finding affected the Initiating Events Cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions, in that operators inappropriately manipulated the steam generator level controls and did not control steam generator levels. The inspectors performed a Phase I Significance Determination Process and determined that the performance deficiency represented a finding of very low risk significance (Green), because it did not contribute to a primary or secondary loss of coolant accident, did not contribute to both the likelihood of a reactor trip and the likelihood that mitigating equipment or function will not be available, and did not increase the likelihood of a fire or internal/external flood. This finding is in licensee’s Corrective Action Program as CR 04-1238. This finding had crosscutting issues associated with human performance because personnel failed to adequately control steam generator levels due to misoperation of plant equipment.

Enforcement. No violation of regulatory requirements occurred.

## 1R15 Operability Evaluations (71111.15)

### a. Inspection Scope

The inspectors selected five operability evaluations conducted by licensee personnel during the report period involving risk-significant systems or components. The inspectors evaluated the technical adequacy of the licensee’s operability determination, determined whether appropriate compensatory measures were implemented, and determined whether or not other pre-existing conditions were considered, as applicable. Additionally, the inspectors evaluated the adequacy of the licensee's problem identification and resolution program as it applied to operability evaluations. Specific operability evaluations reviewed are listed below:

- Unit 1 Train A sequencer caused the loss of the Train A Engineered Safety Features 4160 volt bus on January 19 (CR 04-965)

- (Common) operability of safety related Westinghouse Class 1E 7.5 kV inverters following the failure of Class 1E 7.5 kV Inverter 1201 on February 26 (CR 04-1238)

- Unit 2 engineering evaluation on the condition of loose wedges in Emergency Diesel Generator 22 generator stator on February 27 (CR 04-1039)

- (Common) operability of containment high range radiation monitors RT-8050 and RT-8051 due to temperature induced currents on January 26 (CR 02-16410-3)

- Unit 1 RCS leakage in excess of 1 gpm with no alarm received in the control room on December 17, 2003 (CR 03-18538 and 03-7772)

b. Findings

The Unit 1 RCS leakage in excess of 1 gpm with no alarm received in the control room event on December 17, 2003, will be subject to further review. This issue is an URI pending further review. URI 05000498;499/2004002-02: Reactor Coolant Leakage Detection System Calibration. No other findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors reviewed licensee-identified operator workarounds and other existing equipment conditions with the potential to be workarounds to verify that they had been identified and assessed in accordance with STP's Total Impact Assessment document and to determine if the functional capability of the system or human reliability in responding to initiating events had been affected. The ability of operators to implement normal and emergency operating procedures with the existing equipment issues was specifically evaluated. The following two items were reviewed:

- Unit 1 Emergent - Periodic drain down of the pressurizer relief tank on January 9

- Unit 1 Cumulative - Operation's total impact items list the week of March 29

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17B)

a. Inspection Scope

This inspection is the first week of a two week inspection to satisfy the requirements of Inspection Procedure 71111.17B. The second week of the inspection will be documented in NRC Inspection Report 05000498/2004-004; 05000499/2004-004. The inspection procedure requires a minimum sample size of 5 to 10 plant modifications. The inspector reviewed the permanent plant modification packages listed in the table below and their associated documentation. All of the modifications reviewed were associated with the repair of Standby Diesel Generator 22 in response to the mechanical failure described in NRC Inspection Report 05000498/2004-006; 05000499/2004-006. The inspector reviewed procedures governing plant modifications to evaluate the effectiveness of the programs for implementing modifications, such that the modifications do not adversely affect the design and licensing basis of the facility. Procedures reviewed by the inspector are listed in the attachment to this report. The inspector interviewed the cognizant design and system engineers for the identified modifications to gain their understanding of the modification packages. The inspector also reviewed additional corrective action documents associated with Standby Diesel Generator 22 to ensure that all potential modifications were being treated appropriately.

| Condition Report No. | Description of associated modification |
|---|---|
| 03-18159-13 | Engineering evaluation for repair/replacement of 200 square inches of engine casing on Standby Diesel Generator 22. |
| 03-18159-68 | Drill and install taper pins in the flywheel to facilitate reassembly. |
| 03-18159-105 | Evaluate drilling and reaming center frame to base bolt holes for over-size bolts for #4 cylinder. |
| 03-18159-133 | Repair 4R and 4L split line cracks that run from fitted bolt holes to the outer face of the flange. |
| 03-18159-186 | Evaluate and disposition refurbished master connecting rods that have shortened overall lengths. |

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed postmaintenance test procedures and associated testing activities for six risk-significant mitigating systems. In each case, the associated work orders and test procedures were reviewed against the attributes in Inspection Procedure 71111, Attachment 19, to determine the scope of the maintenance activity and determine if the testing was adequate to verify equipment operability. The Updated Final Safety Analysis Report, Technical Specifications, and design basis documents were also reviewed, as applicable, to determine the adequacy of the acceptance criteria listed in the test procedures. The inspectors witnessed or reviewed the results of postmaintenance testing for the following maintenance activities:

- Unit 1 Plant Maintenance Procedure 0PMP05-VA-0002, "Inverter/Rectifier Maintenance Westinghouse 7.5 KVA," Revision 6, review of postmaintenance testing on Inverter 1201 after replacement on January 24 (Work Authorization Number (WAN) 265147)

- Unit 1 Plant Maintenance Procedure 0PMP05-VA-0002, "Inverter/Rectifier Maintenance Westinghouse 7.5 KVA," Revision 6, review of postmaintenance testing on Inverter 1202 after replacement on January 25 (WAN 267413)

- Unit 1 Plant Maintenance Procedure 0PMP05-CH-0001, "York Chiller Inspection and Maintenance 300 to 550 Tons," Revision 24, review of postmaintenance testing on Train A essential chilled water chiller Unit 12A on February 17 (WAN 223115)

- Unit 2 Standby Diesel Generator 22 jacket water functional testing on March 22 (WAN 269653)

- Unit 2 Standby Diesel Generator 22 lube oil functional testing on April 2 (WAN 269653)

- Unit 2 Temporary Engineering Procedure 2TEP07-DG-0005, "Standby Diesel Generator 22 Return to Service Testing," Revision 0, after rebuild due to thrown rod event on April 4 through 7 (WAN 269653)

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

.1 Review of the Unit 2 Refueling Outage Plan

a. Inspection Scope

The inspectors reviewed the Unit 2 Tenth Refueling Outage (March 31 through April 22, 2004) Shutdown Risk Assessment and the outage schedule to verify that the licensee's outage management appropriately considered risk in planning and scheduling the outage activities. The results of the licensee's Outage Risk Assessment and Management Program, time-to-boil, and time-to-core damage profiles were reviewed against the schedule of activities to identify periods of increased risk and activities for additional inspection focus. The work schedule and risk profiles were discussed with the operations support outage coordinator. The inspectors also observed new fuel receipt inspections on February 20, 2004.

The inspectors focused on the following activities:

- Reactor mode transition operation
- Fuel offload and reload
- Periods with reduced cooling to the spent fuel pool

b. Findings

No findings of significance were identified.

.2 Review of Outage Activities

a. Inspection Scope

Monitoring of Reactor Shutdown and Plant Cooldown Activities

The inspectors observed control room operator actions during the reactor shutdown on March 31, 2004, and assessed the licensee's compliance with Technical Specification limits during the plant cooldown. Plant Operating Procedures 0POP03-ZG-0006, "Plant Shutdown from 100% to Hot Standby," Revision 24, and 0POP03-ZG-0007, "Plant Cooldown," Revision 41, were reviewed.

Midloop Operations

The inspectors observed control room operator actions and plant conditions during midloop activities on April 3, 2004. The inspectors assessed the licensee's compliance with Technical Specifications, use of procedures, and command and control of this critical outage activity. Plant Operating Procedure 0POP03-ZG-0009, "Midloop Operation," Revision 35, was reviewed.

Control of Outage Activities

The inspectors reviewed plant conditions and observed selected refueling outage activities throughout the outage to verify that the licensee maintained the plant in a configuration consistent with the requirements of Technical Specifications and with the assumptions of the outage risk assessment. The inspectors verified that emergent issues were properly assessed for their impact on plant risk.

Electrical power availability was periodically verified to meet Technical Specification requirements and outage risk assessment recommendations. Control room operators were observed and interviewed on the status of plant conditions. The inspectors reviewed equipment tagout activities, and controls for reactivity management, decay heat removal, spent fuel pool cooling, containment integrity, and reactor coolant system inventory.

Refueling Activities

The inspectors observed portions of core offload activities, in order to determine if these activities were conducted in accordance with the Technical Specifications and administrative procedures.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors evaluated the adequacy of six periodic tests of important nuclear plant equipment. This review included aspects such as preconditioning, the impacts of testing during plant operations, the adequacy of acceptance criteria, test frequency, procedure adherence, record keeping, the restoration of standby equipment, test equipment and the effectiveness of the licensee's problem identification and resolution program. The inspectors observed or reviewed the following tests:

- Unit 1 0PMP08-MS-7400, "Main Steam Dump Pressure Control Calibration," Revision 7, on January 13

- Unit 2 0PSP03-SP-0005S, "SSPS Logic Train S Functional Test," Revision 21, on January 22

- Unit 2 0PSP03-AF-0007, "Auxiliary Feedwater Pump 24 Inservice Test," Revision 27, on February 17

- Unit 1 0PEP05-HE-0002, "Control Room Envelope Differential Test," Revision 3, and 0PEP05-HE-0003, "Control Room Envelope Tracer Gas In-leakage Test," Revision 0, on March 1 through 16

- Unit 2 0PSP11-MS-0001, "Main Steam Safety Valve Inservice Test," Revision 14, on March 23

- Unit 2 0PSP03-RC-0010, "Pressurizer Power Operated Relief Valve Operability Test," Revision 8, on March 31

b. Findings

Control Room Envelope HVAC Testing

Introduction. A URI was identified regarding control room envelope HVAC testing that resulted in some control room envelope areas not being a 1/8 inch water gauge positive pressure with respect to an adjacent area as required by Technical Specifications. The licensee requested and received a Notice of Enforcement Discretion (NOED 04-06-001) for Technical Specification requirements.

Description. On March 6, 2004, the licensee completed testing of the Unit 1 control room envelope in accordance with Generic Letter 2003-01, "Control Room Habitability." The testing method used was the component test method described in Nuclear Energy Institute 99-03, "Control Room Habitability Guidance." This test method measures the pressure inside the control room envelope with respect to adjacent areas in a series of locations such that the test points represent the control room boundary and verify that the control room is at a positive pressure with respect to the adjacent area. All leakage should be outleakage from the control room envelope. These results were then to be compared to the tracer gas test method to attempt to validate the component test method as a valid test for determining control room envelope inleakage.

On March 5, 2004, the resident inspectors informed licensee representatives that although the component test was measuring areas that were not in the normal surveillance procedure for Technical Specification compliance; the control room envelope should be considered inoperable since a number of the additional areas were found to fail the 1/8 inch water-gauge requirement detailed in the applicable Technical Specification. On March 17 after consultation with the NRC, the licensee determined that they were in noncompliance and requested a Notice of Enforcement Discretion (NOED). The NOED was requested and approved for both units as discretion was determined to be appropriate as the radiological dose to the control room operators would remain within the limits of General Design Criteria 19 of 10 CFR Part 50, Appendix A. The pressure in the control room envelope remained positive with respect to adjacent areas although some areas did not meet the 1/8 inch water-gauge requirement. Also, in addition to the positive relative pressure condition at all points, the control room makeup and cleanup filtration system remained functional. The licensee implemented compensatory measures which included making potassium iodine and self contained breathing apparatus available until such time as a Technical Specification change could be submitted and approved.

Analysis. The function of the control room ventilation system in its emergency mode lineup is to maintain a positive pressure within the control room envelope with respect to adjacent areas in order to minimize unfiltered inleakage. This assures that the radiological dose to the control room operators remains within the limits of General Design Criteria 19 of 10 CFR Part 50, Appendix A. A significance determination remains to be completed.

Enforcement. This issue is a URI until the associated licensee event report is reviewed for enforcement and significance determination action. This issue is in the licensee's corrective action program under CR 04-3148. URI 05000498;499/2004-002-03, Control Room Envelope HVAC Testing.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the two temporary modifications listed below to assess the following attributes: (1) the adequacy of the safety evaluation; (2) the consistency of the installation with the modification documentation; (3) the updating of drawings and procedures, as applicable; and (4) the adequacy of the post-installation testing. The inspectors also walked down the temporary modifications.

- T2-03-18159-61, "Restore SDG 22 ECW supply relief valve N2EWPSV6865 and vacuum breaker valve 3R282TEW1011 to service," on January 6

- T0-03-18527-1, "Install a temporary diesel generator power source to supply 13.8kV Switchgear 7E150ESG1512Z via cubicle 4," on January 10

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness [EP]

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspector performed an in-office review of Interim Change Notice 20-2 to the South Texas Project Electric Generating Station Emergency Plan. This revision:

- Clarified the emergency response role of the 75-minute operations responder described in Table C-2

- Added the radwaste operator function to the on-shift staffing required by Table C-2

- Revised some titles in the Emergency Response Organization

- Further described communication links between emergency response facilities

- Added criteria for conducting remedial emergency plan exercises

This revision was compared to its previous revision, and to the requirements of 10 CFR 50.47(b) and 50.54(q) to determine if the revision decreased the effectiveness of the emergency plan. The inspector completed one sample during the inspection.

b. Findings

No findings of significance were identified.

## 2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety [OS]

### 2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

This area was inspected to assess performance with respect to maintaining individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspectors used the requirements in 10 CFR Part 20 and the licensee's procedures required by Technical Specification 6.8.1 as criteria for determining compliance. The inspectors interviewed licensee personnel and reviewed:

- Current 3-year rolling average collective exposure
- Three jobs from the forced outage scheduled during the inspection period and associated work activity exposure estimates which were likely to result in the personnel collective exposures
- Site specific ALARA procedures
- Three work activities of highest exposure significance completed during the last outage
- ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements
- Intended versus actual work activity doses and the reasons for any inconsistencies
- Person-hour estimates provided by maintenance planning and other groups to the radiation protection group with the actual work activity time requirements
- Shielding requests, dose/benefit analysis, and follow through
- Post-job (work activity) reviews

- Assumptions and basis for the current annual collective exposure estimate, the methodology for estimating work activity exposures, the intended dose outcome, and the accuracy of dose rate and man-hour estimates

- Corrective action reports related to the ALARA program and follow-up activities such as initial problem identification, characterization, and tracking

The inspectors completed 9 of the required 29 samples.

b. Findings

Introduction. The inspectors identified three examples of a Green, noncited violation of Technical Specification 6.8.1(a) because the licensee failed to follow procedural requirements.

Description. On January 6, 2004, the licensee prepared to transfer Unit 1 waste resin to a reusable waste container. The inspectors observed the initial setup and leak check portion of the task, and noted that operations personnel identified that the task could not be performed as written. Specifically, Step 5.23.1 of Plant Operations Procedure 0POP02-WS-0003, “Waste Transfer to the Portable Solidification System,” Revision 1, required that the operator ensure that “1(2)-WS-0077 HIC Dewatering Lateral #2 Isolation Valve” was open during the dewatering phase of the initial setup and leak check. However, this valve was not the correct valve. The correct valve was “1(2)-WS-0079 HIC Dewatering Lateral #4 Isolation Valve.”

Operations personnel performing the task suspended the evolution to resolve the issue in accordance with Plant General Procedure 0PGP03-ZA-0010, “Performing and Verifying Station Activities,” Revision 25, Step 5.2. The inspectors asked the licensee if this task had been performed previously. The licensee determined that the same task was completed on April 20, July 8, and July 20, 2003, using Plant Operations Procedure 0POP02-WS-0003, Revision 0. The inspectors noted that Step 5.22.1 in Revision 0 was the same as Step 5.23.1 in Revision 1. After interviews with the licensee’s staff, the inspectors concluded that, on the above dates, the licensee did not follow procedural guidance of Plant General Procedure 0PGP03-ZA-0010, because they would have noted the reference to the incorrect valve and resolved the issue by correcting the reference to the incorrect valve.

Analysis. The failures to follow procedural requirements are three examples of a performance deficiency. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC’s regulatory function and was not the result of any willful violation of NRC requirements. The finding is greater than minor because it could be reasonably viewed as a precursor to a significant event and it affected the Occupational Radiation Safety cornerstone objective, which is to ensure adequate protection of worker health and safety from exposure to radiation. The finding is associated with the cornerstone attribute of Program & Process. When the finding was processed through the Occupational Radiation Safety Significance Determination Process, the finding was found to have very low safety significance (Green) because the finding was not associated with ALARA planning or work controls, there was no overexposure or a substantial potential for overexposure, and the ability to assess dose was not compromised.

Enforcement. Technical Specification 6.8.1(a) requires that procedures be established, implemented, and maintained covering the applicable procedures in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Regulatory Guide 1.33, Appendix A, Section 1.d, requires procedures for procedure adherence. Step 5.2 of Plant General Procedure 0PGP03-ZA-0010, “Performing and Verifying Station Activities,” Revision 25, required that station personnel stop and resolve the issue when performance of a procedure step is not expected to achieve the desired result. Ensuring that 1(2)-WS-0077 HIC Dewatering Lateral #2 Isolation Valve was open would not have achieved the desired result. On April 20, July 8, and July 20, 2003, the licensee failed to stop and resolve the issue in accordance with Step 5.2 of Plant General Procedure 0PGP03-ZA-0010.

Three examples of a failure to follow the procedures for performing and verifying station activities are being identified as a Technical Specification 6.8.1(a) violation. Because the finding was determined to be of very low safety significance and entered into the licensee’s Corrective Action Program as CR 04-250, these examples of a violation were treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000498;499/200402-04, Three Examples of a Failure to Follow a Technical Specification Required Procedure.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Initiating Events Performance Indicator Review

a. Inspection Scope

The inspectors reviewed performance indicator data reported by the licensee in order to assess the accuracy and completeness of the information. The inspectors used NEI 99-02, “Performance Indicator Verification,” Revision 2, as guidance for this inspection. Data was reviewed for the following indicators for both units for the first through fourth quarters of 2003:

- Unplanned scrams per 7000 critical hours
- Scrams with loss of normal heat removal
- Unplanned power changes per 7000 critical hours

b. Findings

No findings of significance were identified.

## 4OA2 Identification and Resolution of Problems (71152)

### .1 Inverter Failures

#### a. Inspection Scope

The inspectors performed a detailed review of the licensee's identification and resolution of two recent Class 1E 7.5 kV inverter failures which caused plant transients in December 30, 2003, and January 23, 2004. The first event caused a small power change when Steam Generator PORV 2D opened approximately 12 percent and could not be closed from the control room. The second event resulted in a plant trip when steam generator level could not be controlled. These events were documented by the licensee in Condition Reports 03-18863 and 04-1238. The licensee's extent of condition assessment, operability assessments, and corrective action plan were reviewed and discussed with engineering, operations, and risk assessment personnel. The inspectors evaluated the condition reports against the requirements in the licensee's Corrective Action Program and 10 CFR Part 50, Appendix B.

#### b. Findings and Observations

Introduction. A Green noncited violation of 10 CFR Part 50 Appendix B, Criterion XVI, Corrective Action, was identified for the failure to implement effective corrective action for previous inverter failures that occurred at this site. The safety significance of the finding was determined to be very low.

Description. Class 1E 120 VAC instrument power supply system distribution panels receive power from one of two sources. The normal alignment is from the Class 1E 7.5 kV inverter and the alternate source is from the voltage regulating transformer. A mechanical switch is provided to change from the inverter source to the voltage regulating transformer source. This switch must be manually actuated locally.

The inverter has two power sources. Normal power is from a 480 VAC motor control center. This voltage is reduced, converted to DC and then converted back to AC. The purpose of converting the power from AC to DC is to allow interface with the 125VDC batteries, the alternate power source, which would continue to provide power to the 120 VAC instrument panels.

On December 30, 2003, Unit 2 Class 1E 7.5 kV Inverter 1202 failed resulting in steam generator PORV 2D partially opening to 12 percent. This valve would not close from the control room. Reactor power increased 6 MW thermal and was promptly lowered by reducing turbine load. The PORV was manually isolated and Distribution Panel 1202 was transferred to an alternate power source.

On January 23, 2004, Unit 1 Class 1E 7.5kV Inverter 1201 failed resulting in two steam generator level channels failing low causing full feedwater demand. Operators were unable to take control of the level excursion, resulting in an automatic reactor trip. The loss of the distribution panels powered by the inverters causes the failure of various instrumentation and automatic start signals to plant mitigating equipment. The Train A motor driven and Train D turbine driven auxiliary feedwater pumps did not get automatic start signals.

Failure analysis by an offsite laboratory found that the failure of these two inverters was caused by thermal aging or heat related degradation of their ferro-resonant transformer assemblies.

The investigation conducted by the licensee determined that the design of the Class 1E vital instrument power supply system is not single train fault tolerant and failure of the inverter causes significant operational challenges. These two events occurred because the licensee did not pursue effective failure prevention strategies even though previous events showed that the inverters were susceptible to failure. A historical review revealed that the licensee had experienced 12 failures of these inverters, seven of which required the replacement of the ferro-resonant transformers. Specifically, an event reviewed by the inspectors which occurred on December 28, 1999, (CR 99-17898) revealed a similar failure scenario of the ferro-resonant transformer and internal inverter components, however, no laboratory analysis was performed for the cause of the ferro-resonant transformer failure. Also, events in July 2002 (CR 02-9755), failed to include corrective actions addressing the lack of fault tolerance of the Class 1E 120 VAC instrument power system. Industry events also indicated problems with this type of inverter.

Previous corrective actions were narrowly focused on the operational response and addressing the direct cause of the failure. Even though previous failures were determined to be significant conditions adverse to quality, corrective action to make the instrument power supply system more fault tolerant to inverter failures was not pursued. Despite the fact that the failures of ferro-resonant transformers were involved in previous failures of the inverters, no corrective actions such as initiating preventive maintenance, periodic replacement, developing a new design, or developing a monitoring plan were implemented. This finding also had crosscutting issues associated with problem identification and resolution because personnel failed to correct degraded conditions.

<u>Analysis</u>. The inspectors determined that the failure to implement effective corrective actions following previous failures of the Class 1E 7.5 kV inverters was a performance deficiency and violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action. Reliability of the inverters was reasonably within the licensee’s ability to foresee and correct and these failures could have been prevented. The failure of the above two examples resulted in more significant events, including a plant transient. In accordance with Manual Chapter 0609, Appendix A, Attachment 1, “User Guidance for Significance Determination of Reactor Inspection Findings for At-Power Situations,” the inspectors evaluated the subject finding using the Risk Informed Inspection Notebook for South Texas Project Electric Generating Station, Revision 1. The Phase 1 SDP screening necessitated a Phase 2 evaluation because the finding contributes to both the likelihood

of a reactor trip and the likelihood that mitigating equipment functions will not be available. The Phase 2 evaluation resulted in a finding with a potential of greater than very low safety significance using the counting rule. This necessitated a Phase 3 analysis.

The senior reactor analyst performed an SDP Phase 3 analysis of the finding. The analyst reviewed the load list of the affected Class 1E 120 vac instrument power supply system distribution panels and determined that the most risk-significant items were loss of turbine bypass function as well as automatic pressurizer power-operated relief valve (PORV) operation. The loss of other instrumentation and control loads had little impact on risk. The PORV condition was principally an ATWS mitigation concern, because the bleed and feed capability of the valve was not affected. The significance of the condition was lessened by the fact that the 120 vac instrumentation bus could be re-energized from an alternate power source within 15 minutes by local operator action.

The risk associated with the finding was mostly associated with the increased frequency of plant transients and was only slightly influenced by the loss of instrumentation and control loads. Using the SPAR, Revision 3i model, the analyst calculated a delta-CDF of 5.8E-7/yr. No large early release frequency (LERF) sequences existed. Therefore, the finding was determined to be of very low risk significance.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action, states, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management. The licensee had identified previous failures of the Class 1E 7.5 kV inverters as significant conditions adverse to quality. However, the licensee did not take measures to assure that the cause of the condition was determined and did not implement corrective actions to preclude repetition. Because this finding was determined to be of very low safety significance and was entered into the licensee's Corrective Action Program, it is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy. NCV 05000498;499/2004002-05: Ferro-Resonant Transformer Failures in Class 1E Inverters.

.2 Radiological Protection Inspection

Section 2OS2 evaluated the effectiveness of the licensee's problem identification and resolution processes relating to ALARA planning and control programs. On three occasions, the licensee missed an opportunity to identify and correct an error in procedural guidance. Had workers complied with the guidance in Plant General Procedure 0PGP03-ZA-0010, "Performing and Verifying Station Activities," Revision 25, they would have noted a reference to an incorrect valve.

4OA3 Event Followup (71153)

.1 (Closed) Licensee Event Report 05000498; 499/2003006-00: Unanalyzed Condition That Significantly Degraded Plant Safety Regarding the Natural Circulation Cool Down Rate.

The licensee reported that the existing primary plant cooldown rate limit of 50ºF/hr did not satisfy design basis requirements when one steam generator was not steaming under natural circulation conditions. Specifically, any non-steaming loops could have reactor coolant flow stop, allowing the steam generator to become a heat source as the cooldown progressed to temperatures lower than the steam generator temperature. Analyses showed that rapid cooldowns under these conditions could lead to primary coolant flashing to steam when plant pressure was lowered, causing filling of the pressurizer and loss of reactor coolant system pressure control. The licensee reported this issue because it was concluded that the extra time to cool the plant to the conditions for initiating residual heat removal operation could exceed the capacity of the auxiliary feedwater storage tank. This condition had existed since plant construction.

The licensee implemented an interim compensatory measure to conservatively lower the cooldown rate limit. Corrective actions were in progress to implement changes to emergency and abnormal operating procedures to require restoring forced circulation if reactor coolant pumps are available prior to starting the plant cooldown, and if that is not possible, to steam all steam generators during the plant cooldown. The licensee raised this issue with the Westinghouse Owner's Group for generic consideration, because the existing cooldown rate limit had been established in accordance with Westinghouse Owner's Group Guidelines for natural circulation cooldown. This issue was determined not to represent a performance deficiency because it was not reasonably within the licensee's ability to foresee and correct; the specific conditions that create the problem (one steam generator idle) would appear less limiting than those used in the original analyses (two steam generators idle), which had successfully satisfied the requirements.

The licensee identified that this issue represented a condition that was outside the design basis because the auxiliary feedwater storage tank was not sufficiently large to support a plant cooldown under the most limiting case without needing to be refilled. This licensee-identified violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," is discussed in Section 4OA7. This licensee event report is closed.

.2 (Closed) Licensee Event Report 05000498/2003007-00: Failure of Main Steam Power Operated Relief Valve 1B.

Introduction: A Green noncited violation of 10 CFR Part 50 Appendix B, Criterion XVI, Corrective Action, was identified for the failure to implement effective corrective action for previous main steam PORV failures that occurred at this site.

Description: On December 17, 2003, the Unit 1 main steam PORV 1B hydraulic pump failed to start as required during an operability surveillance test. The licensee determined during the subsequent investigation that the thermal overloads on the hydraulic pump supply breaker had tripped. The cause of the trip was determined to be a 3/8 inch piece of wiring insulation that was inside the contactor for the “C” phase causing a single phasing condition. The piece of insulation caused intermittent contact of phase “C” which resulted in an over current trip of the thermal overloads preventing the hydraulic pump from starting.

Earlier, on November 3, 2003, while performing the same test, an identical failure occurred. At the time, the failure could not be reproduced in six trials. The hydraulic pump was replaced, and the system was tested and placed back in service.

After the investigation for the December 17 event, the licensee concluded that the PORV was functional following the troubleshooting effort on November 3 in all cases except in a seismic event. This was based on the assumption that the movable piece of insulation was in a harmless location during this time and that only a shaking of the breaker cubicle from either a seismic event or the shaking caused by racking the breaker in and out (which occurs during the testing) would move it to a location that could cause the observed malfunction. The shaking which occurred during the testing on December 17 was sufficient once again to move the insulation such that it interrupted the breaker contacts.

The licensee in consultation with the manufacturer concluded that the most likely source of the insulation is during the manufacturing and assembly of the breaker prior to the arrival at the South Texas Project. The licensee therefore determined that main steam PORV 1B had been inoperable from the breaker installation on March 11, 2000, until it was replaced on December 19, 2003, and reported this to the NRC.

The South Texas Project has four main steam PORVs, one on each steam generator. After a transient and the initial opening of all four PORVs, only one PORV is needed to successfully cool down the reactor in the event that the power conversion system is lost. In this case, the initial opening of PORV 1B was not affected, though its long-term operation for reactor plant cooldown was potentially degraded.

Corrective action for this condition included having the vendor address this issue by providing objective evidence of programmatic changes made to prevent reoccurrence. The licensee developed a procedure for the inspection of breaker starter contacts for foreign material prior to installation. This event is in the licensee’s corrective action program as CR 03-18545. This finding also had crosscutting issues associated with problem identification and resolution because personnel failed to correct degraded conditions.

<u>Analysis</u>: The inspectors determined that the failure to identify the root cause of the hydraulic pump failure on November 3, 2003, was a performance deficiency. Therefore, main steam PORV 1B was in a degraded condition from that time until December 19, 2003, when the breaker was replaced. Because the finding involved the potential loss of a risk-significant component, it did not meet the criteria in MC 0612, Appendices B and E, for categorization as a minor issue.

The adrift piece of insulation caused only an occasional interruption in the mating of the breaker contacts. This condition occurred once during the testing on November 3 and once during the testing on December 17. Following each of these occurrences, six tests were conducted in an attempt to recreate the failure, but all of the retests were successful. Both of the test failures occurred after the breaker was disturbed by racking it in and out. Therefore, it is probable that when the breaker was racked in the final time and a successful test was performed, it would have performed successfully the next time it was called into service unless it was subjected to a physical shaking associated with an earthquake. This assumption is further supported by the fact that the hydraulic pump normally cycles on for approximately one minute every three days to repressurize the valve accumulator. If the pump breaker had tripped during this time, a low pressure alarm would have alerted operators to this condition, and the breaker would have been found to be in a tripped configuration. This did not occur throughout the exposure period of the finding. Therefore, it can be concluded that during this 46-day period, the hydraulic pump operated successfully on approximately 15 occasions. A Senior Reactor Analyst concluded from the facts presented above that during the exposure period, the hydraulic pump and, thus, the PORV would have operated successfully in response to any event that did not also produce a physical shaking of the breaker cubicle. This shaking could only result from a seismic event.

The analyst evaluated the finding under the external events screening criteria on Page 3 of 3 of the Phase I screening worksheets in MC 0609, Appendix A. The relevant question on this page (#3) asks whether the finding involves a total loss of a safety function that contributes to external events initiated core damage sequences. This question can be answered “no” because three other PORVs were available for use in a reactor coolant system cooldown. Therefore, the analyst determined that the finding screens as very low risk significance (GREEN) under Phase 1 of the SDP.

Even if the ability of the secondary system to remain intact is considered a “safety function” and it is recognized that the PORV could fail open, the analyst was confident that the finding would remain “Green” based on the low initiating event frequencies associated with seismic events, the ability to manually isolate a stuck-open main steam PORV, and reference to the licensee’s evaluation discussed below.

The licensee evaluated the finding and estimated that the risk was minimal (ICCDP=2E-9). The licensee’s evaluation assumed that the PORV would always fail closed during a seismic event. An exposure time of about 3.5 years was used, which was the length of time the breaker had been in service. This represented a time window 30 times greater than the exposure period associated with the performance deficiency. Taking this into account would result in an ICCDP of 7E-11.

Although the licensee’s evaluation did not include the possibility that the valve could stick open and cause a secondary system LOCA, the analyst concluded that the addition of this failure mode would not significantly change the result. This was based on the analyst’s judgement that the probability and consequences of the PORV failing open were on the same order of magnitude as if it failed closed (isolating a stuck-open main steam PORV is easily diagnosed and performed).

Enforcement: 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action, states, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management. The licensee had identified the previous failure of main steam PORV 1B hydraulic pump as a condition adverse to quality. However, the licensee did not take adequate measures to assure that the cause of the condition was determined and did not implement appropriate corrective actions to preclude repetition. Because the finding was determined to be of very low safety significance (Green) and entered into the licensee's Corrective Action Program as CR 03-18545, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000498/2004002-06, Failure of Main Steam Power Operated Relief Valve 1B.

4OA4 Crosscutting Aspects of Findings (71152)

Section 1R14 of this report documents a human performance error for inappropriate operator response to an event resulted in a plant transient.

Section 4OA2 of this report documents a problem identification and resolution error for failure to implement effective corrective action for previous Class 1E 7.5 kV inverter failures.

Section 4OA3 of this report documents a problem identification and resolution error for failure to implement effective corrective action for previous main steam power operated relief valve hydraulic motor failures.

4OA5 Other

.1 (Closed) Unresolved Item 05000498/2003004-01: Pressurizer Power Operated Relief Valve Lift at Full Power Operations

Introduction: A Green NCV was identified for an inadequate procedure for equipment calibration that resulted in a pressurizer PORV lifting while Unit 1 was at 100 percent power. Plant Surveillance Procedure 0PSP02-RC-0455, "Pressurizer Pressure ACOT," inappropriately allowed performance of the procedure with any channel combination selected. This resulted in PORV PCV-0656A opening while the reactor was at power. The failure to establish an appropriate procedure for testing pressurizer pressure instrumentation was identified as a violation of Technical Specification 6.8.1 and a Regulatory Guide 1.33 required procedure. The inspectors determined that the failure was a licensee performance deficiency and the procedure deficiency was reasonably within the licensee's ability to foresee and correct.

Description: On March 12, 2003, a Unit 1 a pressurizer PORV lifted during a pressurizer pressure channel calibration. The plant was at 100 percent power at the time of the event. Plant Surveillance Procedure 0PSP02-RC-0455, “Pressurizer Pressure ACOT,” Revision 15, allowed performing the calibration surveillance with any channel combination selected. Control room operators and the instrumentation and control (I&C) technicians discussed this anomaly but concluded that the procedure must have been successfully completed in the past since there were no revision bars next to the applicable steps. They were unaware that a number of revisions had been issued since the last time the procedure had been completed. The control room operators and the I&C technicians failed to recognize that the channel being tested, although not the channel controlling the master pressure controller, was controlling the PORV that subsequently opened when the calibration test signal exceeded the setpoint for the PORV. The PORV reclosed after seven seconds when the I&C technicians dialed the calibration test signal down in accordance with the procedure. They were unaware that the valve had opened. The action of the PORV resulted in a pressurizer pressure drop from 2235 to 2193 psig and a decrease of approximately 0.8 percent in pressurizer level. Plant Surveillance Procedure 0PSP02-RC-0455, “Pressurizer Pressure ACOT,” Revision 15, was inadequate because it allowed the calibration surveillance to be performed in a manner which resulted in a breach in the reactor coolant system.

The error was introduced in Revision 13 of the above procedure as a result of a procedure feedback form generated by operations personnel which was misunderstood by the procedure writer. In response to the feedback form, the procedure writer revised the wrong section of the procedure. Another unrelated procedure change request was also submitted resulting in Revision 14, which still contained the channel selection error. Revision 14 was determined to contain additional errors and Revision 15 was issued with the channel selection error still in place. When Revision 15 was issued the revision bars identifying the changes incorporated with Revision 13 and 14 were deleted. The failure of the licensee’s review and comment process to identify the channel selection error was identified as a contributing cause of the event. Following the event, Revision 16 was issued and this revision corrected the channel selection error.

Analysis: This finding is greater than minor because it was similar to Example 4.b in NRC Inspection Manual Chapter 0612, Appendix E, “Example of Minor Issues,” and it met the “not minor if” criteria in that the error resulted in a plant transient. The Significance Determination Process (SDP) Phase 1 worksheet directed the inspectors to perform a SDP Phase 2 analysis since both the initiating events and reactor coolant system barrier cornerstones were impacted by the inadequate procedure.

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, "User Guidance for Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors evaluated the finding using the Risk-Informed Inspection Notebook for South Texas Project Electric Generating Station, Revision 1. The following assumptions were made:

- The faulty procedure would only be conducted once in a configuration that resulted in the PORV inadvertently opening. Therefore, the exposure time for this deficiency was the less than three days.

- The safety function of the PORV was not affected by this performance deficiency. The PORV would have responded to a high pressure signal throughout the test procedure, except when the channel was removed from service for routine testing.

- The initiating event likelihood credit for a stuck-open power-operated relief valve was increased from four to two by the Senior Reactor Analyst from Region IV in accordance with Usage Rule 1.2 in Manual Chapter 0609, Appendix A, Attachment 2, "Site Specific Risk-Informed Inspection Notebook Usage Rules." This change reflects the fact that the valve was open and that the conditional failure rate of pressurizer PORVs to reclose upon opening is 1.6 percent. This number was provided by the Idaho National Engineering and Environmental Laboratory in the plant specific SPAR model documentation. The deviation from the risk-informed notebook represents a Phase 3 analysis in accordance with Manual Chapter 0609, Appendix A, Attachment 1, in the section entitled: "Phase 3 - Risk Significance Estimation Using Any Risk Basis That Departs from the Phase 1 or 2 Process."

- Stuck-open relief valve (SORV) is a special initiator in the South Texas Notebook. This is the only initiating event that is affected by the finding.

Table 2 of the risk-informed notebook provides multiple worksheets for evaluation when a performance deficiency affects the PORVs. However, given that the PORV function was not degraded, only the sequences with SORV were applicable to this evaluation. The sequences from the notebook were as follows:

| Initiating Event | Sequence | Mitigating Functions | Results |
|---|---|---|---|
| Stuck-Open Relief Valve | 1 | BLK - LPR | 7 |
| Stuck-Open Relief Valve | 2 | BLK - AFW - FB | 10 |
| Stuck-Open Relief Valve | 3 | BLK - EIHP | 7 |

The Phase 2 analysis estimated the finding to be GREEN. However, because a modification was made to the Phase 2 process and because the result was equal to 7, a Phase 3 evaluation was required.

The SDP Phase 3 analysis was performed by a Senior Reactor Analyst from Region IV. The results from the modified notebook estimation were compared with an evaluation developed using a Standardized Plant Analysis Risk (SPAR) model simulation of the

PORV opening, as well as an assessment of the licensee's evaluation provided by the licensee's probabilistic risk assessment staff.

The results of the Phase 3 analysis corroborated the result from the risk-informed notebook. In addition, the Phase 3 results indicated that neither further evaluation of the large early release freuency nor evaluation of external initiators was required. Therefore the analysis characterized the performance deficiency as an issue of very low safety significance (Green).

Enforcement: Technical Specification 6.8.1.a requires that procedures be established, implemented, and maintained covering the applicable procedures in Appendix A of Regulatory Guide 1.33. Appendix A, Item 8.b, requires procedures be maintained for the surveillance tests listed in the Technical Specifications. Plant Surveillance Procedure 0PSP02-RC-0455, "Pressurizer Pressure ACOT," Revision 15, was not properly maintained in that it was inadequate because it allowed performing the calibration surveillance with any channel combination selected causing, on March 12, 2003, a pressurizer PORV to lift while the plant was at 100 percent power. The failure to maintain the procedure was determined to be of very low safety significance and has been entered into the licensee's Corrective Action Program in Condition Records 02-18063 and 03-3929. This violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000498/2004-002-07, Pressurizer Power Operated Relief Valve Lift at Full Power Operations.

4OA6 Meetings, Including Exit

The results of the radiation protection inspection were presented to Mr. J. Sheppard, President and Chief Executive Officer, and other members of his staff on January 8, 2004.

The results of the emergency preparedness inspection were presented to Mr. A. Morgan, Supervisor, Emergency Preparedness, and other members of his staff during a telephonic exit interview on January 14, 2004.

The results of the permanent plant modification inspection were presented to Mr. W. Harrison, Senior Licensing Engineer, and other members of licensee management on March 25, 2004.

The results of the onsite and in-office followup inspection were presented to Mr. J. Sheppard and other members of his staff , who acknowledged the findings on April 15, 2004.

The results of the resident inspection were presented to Mr. J. Sheppard, President and Chief Executive Officer, and other members of licensee management on April 15, 2004.

In each case, the inspectors asked the licensee representatives whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

Other Meetings

On January 15, 2004, Mr. Art Howell, Director, Division of Reactor Projects, Region IV, toured the plant and visited with licensee management.

On January 21, 2004, Dr. Bruce Mallet, Regional Administrator, Region IV, toured the plant and visited with licensee management

40A7 Licensee-identified Violations

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 Enforcement Policy, NUREG 1600, for being dispositioned as a noncited violation.

- Appendix B to 10 CFR Part 50, Criterion III, "Design Control," requires that applicable regulatory requirements and the design basis for the structures, systems and components for which Appendix B applies shall be translated into specifications, drawings, procedures and instructions. Contrary to this, on December 9, 2003, the licensee identified that the existing cooldown rate limit during natural circulation was too high to allow cooling down the plant without refilling the auxiliary feedwater storage tank under one design basis condition. This was documented in the licensee's corrective action program under Condition Reports 03-3998, 03-17841, and 04-3341. This violation is more than minor because it is similar to Example 3.i of Manual Chapter 0612, Appendix E. This violation is of very low safety significance because the licensee had multiple methods of refilling the auxiliary feedwater storage tank that were proceduralized and trained upon, including using diesel-driven fire pumps that were independent of offsite power.

ATTACHMENT: SUPPLEMENTAL INFORMATION

## SUPPLEMENTAL INFORMATION

## KEY POINTS OF CONTACT

Licensee

R. Aguilera, Supervisor, Radiation Protection
C. Albury, Supervising Engineer
M. Berrens, Manager, Generations Support
W. Bullard, Manager, Health Physics
J. Calvert, Manager, Operations Training
K. Coates, Manager, Maintenance
F. Cox, Design Engineer
J. Crenshaw, Manager, Plant Engineering
R. Gangluff, Manager, Chemistry
E. Halpin, Plant General Manager
W. Harrison, Senior Licensing Engineer
S. Head, Manager, Licensing
B. Jenewein, Manager, Plant Generation Systems
J. Johnson, Supervisor, Quality
T. Jordan, Vice President, Engineering and Technical
D. Leazar, Manager, Nuclear Fuels and Analysis
J. Mertink, Manager, Operations Division - Unit 1
A. Mikus, Supervisor, Communication and Public Affairs
A. Morgan, Supervisor, Emergency Response
G. Parkey, Vice President, Generation
U. Patil, Design Engineer
C. Pham, Engineer, Mechanical/Civil Design
D. Rencurrel, Manager, Operations
W. Russell, Procedure Supervisor
R. Savage, Licensing Engineer
P. Serra, Manager, Plant Protection
J. Sheppard, President and CEO
C. Stone, Supervisor, Health Physics
K. Taplett, Licensing Engineer
S. Thomas, Manager, Engineering Projects
D. Towler, Manager, Quality
T. Walker, Manager, Quality
J. Winters, System Engineer

## LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Open

| | | |
|---|---|---|
| 05000498/2004002-01 | URI | Inadequate Procedure Results in Relief Valve Opening (Section 1R14.1) |
| 05000498;499/2004002-02 | URI | Reactor Coolant Leakage Detection System Calibration (Section 1R15) |

| | | |
|---|---|---|
| 05000498;499/2004002-03 | URI | Control Room Envelope HVAC Testing (Section 1R22) |
| 05000498;499/2004002-04 | NCV | Three examples of the failure to follow Technical Specification required procedure (Section 2OS2) |
| 05000498;499/2004002-05 | NCV | Ferro-Resonant Transformer Failures in Class 1E Inverters (Section 4OA2.1) |
| 05000498/2004002-06 | NCV | Failure of Main Steam Power Operated Relief Valve 1B (Section 4OA3.2) |
| 05000498/2004002-07 | NCV | Pressurizer Power Operated Relief Valve Lift at Full Power Operations (Section 4OA5) |

<u>Closed</u>

| | | |
|---|---|---|
| 05000498;499/200402-04 | NCV | Three examples of the failure to follow Technical Specification required procedure (Section 2OS2) |
| 05000498;499/2004002-05 | NCV | Ferro-Resonant Transformer Failures in Class 1E Inverters (Section 4OA2.1) |
| 05000498/2004002-06 | NCV | Failure of Main Steam Power Operated Relief Valve 1B (Section 4OA3.2) |
| 05000498/2004002-07 | NCV | Pressurizer Power Operated Relief Valve Lift at Full Power Operations (Section 4OA5) |
| 05000498/2003004-01 | URI | Pressurizer Power Operated Relief Valve Lift at Full Power Operations (Section 4OA5) |
| 05000498;499/2003006-00 | LER | Unanalyzed Condition That Significantly Degraded Plant Safety Regarding the Natural Circulation Cool Down Rate (Section 4OA3) |
| 05000498/2003007-00 | LER | Failure of Main Steam Power Operated Relief Valve 1B (Section 4OA3.2) |

## LIST OF DOCUMENTS REVIEWED

In addition to the documents identified in the inspection report, the following documents were selected and reviewed by the inspectors to accomplish the objectives and scope of the inspection and to support any findings:

Corrective Action Reports: CR 03-11896, CR 03-12369, CR 03-13475, CR 03-14754, CR 03-16621, CR 03-16740, CR 03-17019, CR 03-17050, CR 04-248, CR 04-250, CR 04-287, CR 04-292, CR 04-334, CR 04-359, CR 04-376

Site ALARA Committee Minutes for September 30, 2003 and October 13, 2003.

Quality Audit Report 03-13 (RC), Radiological Controls/Radwaste Program dated 12/17/03.

Radiation Work Permits (Work Activity Number-WAN):
Bottom Mounted Instrumentation (BMI) Penetration 31 Restoration, RWP 2003-1-0245 (WAN 253220)
Reactor Head Disassembly/Reassembly, RWP 2003-1-218 (WAN 250718)
Insulation Removal and Reinstallation BMI repairs, RWP 2003-1-0227 (WAN 251030)

Procedures:
0PGP03-ZR-0050, Radiation Protection Program, Revision 7
0PGP03-ZR-0051, Radiological Access and Work Controls, Revision 18
0PGP03-ZR-0052, ALARA Program, Revision 6
0PGP03-ZR-0048, Personnel Dosimetry Program, Revision 10
0PGP07-ZR-0004, Temporary Shielding, Revision 8
0PGP07-ZR-0009, Performance of High Exposure Work, Revision 20
0PGP07-ZR-0010, Radiation Work Permits, Revision 12
0PGP07-ZR-0011, Radiological Work ALARA Reviews, Revision 4
0PRP02-ZR-0010, Personnel Exposure Investigation, Revision 7
0PGP03-ZA-0010, Performing and Verifying Station Activities, Revision 25
0POP02-WS-0003, Waste Transfer to the Portable Solidification System, Revision 0
0POP02-WS-0003, Waste Transfer to the Portable Solidification System, Revision 1

Procedures

0PGP03-ZO-0003, "Temporary Modifications," Revision 20

0PGP04-ZA-0002, "Condition Report Engineering Evaluation," Revision 5

0POP01-ZA-0049, "Condition Report Operations Evaluation Program," Revision 3

0POP02-EW-0001, "Essential Cooling Water Operations," Revision 31

0POP10-AE-0001, "Emergency AC Electrical Supply to the Opposite Unit," Revision 2

0TOP04-AE-0001, "Supplying Emergency Power from the GE Power System (GEPS)," Revision 2

Condition Reports

| | | | |
|---|---|---|---|
| 03-18159-13 | 03-18159-66 | 03-18159-130 | 03-18159-183 |
| 03-18159-14 | 03-18159-68 | 03-18159-133 | 03-18159-184 |
| 03-18159-15 | 03-18159-71 | 03-18159-137 | 03-18159-186 |
| 03-18159-39 | 03-18159-72 | 03-18159-142 | 03-18159-188 |
| 03-18159-40 | 03-18159-83 | 03-18159-143 | 03-18159-190 |
| 03-18159-43 | 03-18159-87 | 03-18159-152 | 03-18159-194 |
| 03-18159-44 | 03-18159-88 | 03-18159-153 | 03-18159-198 |
| 03-18159-47 | 03-18159-90 | 03-18159-155 | 03-18159-200 |
| 03-18159-49 | 03-18159-95 | 03-18159-170 | 03-18159-204 |
| 03-18159-54 | 03-18159-101 | 03-18159-171 | 03-18159-206 |
| 03-18159-56 | 03-18159-105 | 03-18159-175 | 03-18751 |
| 03-18159-64 | 03-18159-118 | 03-18159-176 | 04-2041-1 |
| 03-18159-65 | | | |

Documents Reviewed for Section 4OA3:

**Condition Reports:**

03-3998
03-17841
04-3341

**Miscellaneous Documents:**

Updated Final Safety Analysis Report, Chapter 15

5A011MC6023, Appendix R Evaluation, Revision 9

NC-7079, Fire Hazards Analysis, Revision 0

5A019MFP001, Post Fire Operator Actions and Equipment Protection Requirements, Revisions 10 and 12 (common name: Operator Actions List)

## LIST OF ACRONYMS

| | |
|---|---|
| ALARA | As Low As is Reasonably Achieved |
| CFR | *Code of Federal Regulations* |
| CR | condition report |
| ESF | emergency safety features |
| HVAC | heating, ventilation, and air conditioning |
| I&C | instrumentation and control |
| LER | licensee event report |
| NCV | noncited violation |
| NOED | notice of enforcement discretion |
| P&ID | piping and instrumentation diagram |
| PORV | power operated relief valve |

| | |
|---|---|
| RCPB | reactor coolant pressure boundary |
| RCS | reactor coolant system |
| SDP | significance determination process |
| SORV | stuck-open relief valve |
| UFSAR | updated final safety analysis report |
| URI | unresolved item |
| WAN | work authorization number |