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

August 5, 2003

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 05000498/2003002 AND 05000499/2003002

Dear Mr. Sheppard:

On June 21, 2003, the NRC completed an inspection at your South Texas Project Electric Generating Station, Units 1 and 2, facility. The enclosed report documents the inspection findings which were discussed on July 1, 2003, with Mr. G. Parkey and other 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. Within these areas, the inspection consisted of selected examination of procedures and representative records, observations of activities, and interviews with personnel.

Based on the results of this inspection, the NRC has identified eight issues. Six of these issues were evaluated under the risk significance determination process (SDP) as having very low safety significance (Green). These issues were violations which are being treated as noncited violations (NCVs), consistent with Section VI.A of the Enforcement Policy. The NCVs are described in the subject inspection report. If you contest the violations or significance of the NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the South Texas Project Electric Generating Station, Units 1 and 2, facility.

Since the terrorist attacks on September 11, 2001, NRC has issued five Orders and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance controls over access authorization. In addition to applicable baseline inspections, the NRC issued Temporary Instruction 2515/148, "Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures," and its subsequent revision, to audit and inspect licensee implementation of the interim compensatory measures required by order. Phase 1 of TI 2515/148 was completed at all commercial power nuclear power plants during Calender Year 2002 and the remaining inspection activities for the South Texas Project were completed in March 2003. The NRC will continue to monitor overall safeguards and security controls at the South Texas Project.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response 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).

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

Sincerely,

/RA/

William D. Johnson, Chief
Project Branch A
Division of Reactor Projects

Dockets: 50-498
50-499
Licenses: NPF-76
NPF-80

Enclosure:
NRC Inspection Report 05000498/2003002 and 05000499/2003002
w/Attachment: Supplemental Information

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-498 50-499
Licenses:	NPF-76 NPF-80
Report No:	05000498/2003002 05000499/2003002
Licensee:	STP Nuclear Operating Company
Facility:	South Texas Project Electric Generating Station, Units 1 and 2
Location:	FM 521 - 8 miles west of Wadsworth Wadsworth, Texas 77483
Date:	March 23 through June 21, 2003
Inspectors:	N. F. O'Keefe, Senior Resident Inspector G. L. Guerra, Resident Inspector D. B. Allen, Senior Resident Inspector, Comanche Peak P. J. Elkmann, Emergency Preparedness Inspector J. M. Keeton, Project Engineer, Project Branch A G. A. Pick, Senior Physical Security Inspector M. P. Shannon, Senior Health Physicist W. C. Sifre, Reactor Inspector
Approved By:	W. D. Johnson, Chief Project Branch A Division of Reactor Projects

CONTENTS

SUMMARY OF FINDINGS

IR05000498/2003002; IR05000499/2003002; 3/23/2002-06/21/2003; South Texas Project Electric Generating Station; Units 1&2. Integrated Resident & Regional Rpt; event followup, other activities, maint. implementation, maint. risk, ALARA planning & controls.

The report covered a 3-month period of inspection by resident inspectors and region-based engineering and plant support inspectors. Six Green noncited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, “Significance Determination Process.” Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- TBD. Unit 1 operators responded inappropriately during a shutdown event. With the plant operating in a water-solid condition, Unit 1 experienced a series of pressurizer power-operated relief valve lifts and resulting pressure transients. Operators were unable to diagnose the problem due to the rapid plant response. As a result, operators briefly reinitiated the leak and subsequently isolated all the Technical Specification-required low temperature over pressure protection paths inappropriately. The event was caused, in part, because operators did not understand and control the impact of restoration of power to an instrumentation panel and did not understand the interactions between the normal controller and the cold overpressure mitigation system.

  This issue is unresolved pending completion of a significance determination (Section 4OA3).

- Green. A noncited violation was identified for failure to follow a plant procedure, which contributed to collecting enough nitrogen in the reactor head to displace about 4000 gallons of reactor coolant during shutdown maintenance activities before it was recognized. Plant Operating Procedure 0POP03-ZG-0007, "Plant Cooldown," Revision 36, required the head vent valves to be open in this plant condition to vent gases and prevent them from collecting in the reactor head area. The operators did not fully assess this unusual evolution or apply increased controls, in part because a similar evolution had been successfully performed 2 months earlier. However, the earlier work had not required the head vent path to be isolated. This issue was entered in the licensee’s corrective action program under Condition Reports 03-2751 and 03-3443.

  This issue is greater than minor because it affected the Initiating Events Cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions (inventory control) during shutdown operations due to human performance. This issue is of very low safety significance because operators were monitoring backup level indications which were less sensitive but unaffected by the gas accumulation and because the gas accumulation would have been self-limiting if it had progressed to the pressurizer surge line (a vent path) (Section 4OA5.2).

- Green. A noncited violation was identified for the failure to manage the assessed risk consequences of a heavy load lift over operating residual heat removal trains as prescribed in 10 CFR 50.65(a)(4), maintenance rule. During the recent Unit 1 outage at Mode 5, the licensee removed the reactor coolant Pump 1B motor from containment without following the requirements of station procedures developed to mitigate the risk associated with heavy load lifts. The licensee lost focus of this risk mitigating procedure and lifted the motor over residual heat removal Trains A and B without isolating them from the reactor coolant system as required by the procedure. This finding is in the licensee's corrective action program as Condition Report 03-5296.

  This finding is greater than minor because it affects the initiating events cornerstone by increasing the likelihood of an initiating event. If a load drop would have occurred, it could have caused a shutdown loss of coolant accident. The finding is of very low safety significance because the licensee maintained mitigating equipment available (Section 1R13).

- Green. A noncited violation was identified for the failure to manage the associated risk consequences of performing on-line maintenance on medium risk ranked plant equipment without following station procedures for mitigating the risk as prescribed in 10 CFR 50.65(a)(4), maintenance rule. Steam Generator Feed Pump 22 tripped while performing minor maintenance to replace a redundant power supply while at power. Weekend shift maintenance and operations crews did not recognize this work as being a medium trip risk evolution and treat it accordingly, resulting in relying on standby equipment and tripping a main feedwater pump. This work should have been characterized as a Medium Risk Evolution and treated in accordance with station procedures. This finding is in the licensee's corrective action program as Condition Report 03-7221.

  This finding is greater than minor because it affects the initiating events cornerstone by increasing the likelihood of an initiating event (plant transient). If the startup feed pump had not started, it may have caused a turbine/reactor trip. The finding is of very low safety significance because other standby equipment operated as required (Section 1R13).

Cornerstone: Mitigating Systems

- TBD. The inspectors identified an issue related to ineffective maintenance practices for motor-operated valve actuators that resulted in failure of a residual heat removal valve actuator and numerous similar problems in other valve actuators. Specifically, a 10 CFR Part 50, Appendix B, Criterion V, issue was identified for failing to implement procedural requirements to develop, perform, track, and close out corrective actions for vendor technical bulletins/advisories. A 1989 vendor advisory alerting the licensee to failures of motor-operated valve actuators and recommending corrective measures was incorporated into station maintenance procedures without taking action to assure actuators in the plant were actually corrected.

  This issue is unresolved pending completion of a significance determination (Section 1R12).

Cornerstone: Occupational Radiation Safety

- Green. A self-revealing noncited violation was identified because the licensee failed to follow the requirements of a Technical Specification 6.8.1a required procedure. Specifically, on March 31, 2003, two workers failed to have health physics personnel coverage prior to breaching a contaminated system associated with Reactor Coolant Pump 1B, as required by their Radiation Work Permit 2003-1-0098.

  The failure to follow the requirements of a Technical Specification required procedure is a performance deficiency. The issue was more than minor because it is associated with a cornerstone attribute (program and process) and affected the Occupational Radiation Safety cornerstone objective (to ensure the adequate protection of the worker's health and safety from exposure to radiation from radioactive material). The finding involved the failure to control radiological work that was contrary to Technical Specification requirements. When processed through the Occupational Radiation Safety Significance Determination Process, the finding was found to have very low safety significance because it was not an ALARA issue, there was no overexposure or substantial potential for an overexposure, and the ability to assess dose was not compromised (Section 2OS1).

- Green. An NRC identified noncited violation of 10 CFR 20.1501a was identified because the licensee failed to perform an adequate airborne survey during decontamination activities. Specifically, during a review of surveys the inspectors identified two examples in which air samplers were not properly positioned to ensure work area airborne radiological conditions were monitored.

The failure to appropriately position air samplers to perform a representative airborne survey of a work area is a performance deficiency. The issue was more than minor because it was associated with a cornerstone attribute (program and process) and affected the occupational radiation safety cornerstone objective (to ensure the adequate protection of the worker's health and safety from radiation and radioactive material). The finding involved the failure to control radiological work that was contrary to regulatory requirements. When processed through the Occupational Radiation Safety Significance Determination Process, the finding was found to have very low safety significance because it was not an ALARA issue, there was no overexposure or substantial potential for an overexposure, and the ability to assess dose was not compromised (Section 2OS1).

- Green. A self-revealing noncited violation of 10 CFR 19.12 was identified because the licensee failed to inform a radiation worker of the radiological conditions in the work area. Specifically, a worker failed to get briefed on the work area radiological conditions at the Unit 1 health physics access point. Additionally, a health physics technician providing job coverage did not inform the worker of the conditions.

  The failure to inform a worker of the radiological conditions in a work area is a performance deficiency. The issue was more than minor because it was associated with a cornerstone attribute (program and process) and affected the occupational radiation safety cornerstone objective (to ensure the adequate protection of the worker's health and safety from radiation and radioactive material). The finding involved the failure to control radiological work that was contrary to regulatory requirements. When processed through the Occupational Radiation Safety Significance Determination Process, the finding was found to have very low safety significance because it was not an ALARA issue, there was no overexposure or substantial potential for an overexposure, and the ability to assess dose was not compromised (Section 2OS1).

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 in coastdown operations. The plant was shutdown on March 26, 2003, for a scheduled refueling outage. The unit remained shutdown through the remainder of the inspection period to investigate and repair leakage identified at two bottom mounted instrumentation thimble penetrations on the lower reactor vessel head.

Unit 2 began the inspection period at full power. Power was reduced to 82 percent on May 31, 2003, to perform maintenance on a main turbine governor valve. Power was returned to 100 percent the same day, and the unit remained at the full power through the end of the inspection period.

2. REACTOR SAFETY
Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

During the week of June 16, 2003, the inspectors completed a review of the licensee's adverse weather preparations for the hurricane season. The inspection included a review of the following licensee procedures:

- 0PGP03-ZV-0001, "Severe Weather Plan," Revision 8
- 0POP04-ZO-0002, "Natural or Destructive Phenomena Guidelines," Revision 22

The inspectors reviewed individual departmental plans and checklists completed prior to the start of hurricane season. Discussions were held with the licensee's emergency preparedness coordinator to assess the extent and completeness of preparations. The inspectors accompanied a licensee team on a walkdown of the owner controlled area and the protected area. The licensee team identified potential missiles and equipment that would require sheltering. Inventories of essential supplies were also verified. The inspectors specifically reviewed hurricane and tornado preparations for the following risk-significant systems by performing walkdowns of the system enclosures and exposed features in accordance with inspection procedure guidance:

- Units 1 and 2 main transformers and site switchyard
- Units 1 and 2 essential cooling water building and intake structure

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

Partial System Walkdowns

a. Inspection Scope

Three partial system walkdowns were performed.

The inspectors performed a partial system walkdown of the Unit 2 Train B auxiliary feedwater system during a Train A workweek on April 23, 2003. The inspectors walked down system equipment, valve and electrical lineup, and control boards using Plant Operating Procedure 0POP02-AF-0001, “Auxiliary Feedwater,” Revision 18, to verify that the standby train was in a proper operational and standby lineup. The inspectors also examined component material condition of the system.

The inspectors performed a partial system walkdown of the Unit 2 technical support center diesel generator and positive displacement pump during the extended allowed outage for the Train C essential cooling water pump on May 6, 2003. The inspectors walked down system equipment and control boards using Plant Operating Procedure 0POP02-DB-0005, “Technical Support Center Diesel Generator,” Revision 21, and 0POP02-CV-0004, “Chemical and Volume Control System Subsystem,” Revision 32, to verify that the trains were in proper operational and standby lineups. These systems were required to be operational as risk mitigation measures in support of the extended allowed outage for the essential cooling water pump. The inspectors also examined component material condition of the potions of the systems inspected.

The inspectors performed a partial system walkdown of the Unit 2 Train B essential cooling water system while Train A was shut down for maintenance during the week of June 16, 2003. The inspectors verified the proper equipment and control board lineups in accordance with Plant Operating Procedure 0POP02-EW-0001, “Essential Cooling Water Operations,” Revision 28. The inspectors also examined component material condition.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Routine Fire Area Walkdowns

a. Inspection Scope

The inspectors used Inspection Procedure 71111.05 to evaluate the control of transient combustibles and ignition sources. The licensee's individual plant examination, fire preplans, and Fire Hazards Analysis Report were used to identify important plant equipment, design fire loading, fire detection and suppression equipment locations, and planned actions to respond to a fire in each of the plant areas selected. The inspection included observing the operational lineup and material condition of fire protection systems and fire barriers used to prevent fire damage or propagation. The following six plant areas were inspected:

- Unit 1 electrical auxiliary building Train A penetrations on March 26, 2003 (Fire Zone 001)
- Unit 1 reactor containment building during refueling outage 1RE11 on April 1 and 2, 2003 (Fire Area 63)
- Unit 1 electrical auxiliary building auxiliary shutdown room on April 18, 2003 (Fire Zone 071)
- Unit 2 electrical auxiliary building auxiliary shutdown room on April 30, 2003 (Fire Zone 071)
- Common fire pump house on May 1, 2003 (Fire Zone 800)
- Unit 2 electrical auxiliary building Train B electrical switchgear room 212 on June 17, 2003 (Fire Zone Z042)

b. Findings

No findings of significance were identified.

.2 Fire Brigade Drills

a. Inspection Scope

For this inspection the inspectors observed portions of two announced fire brigade drills on May 7 and 14, 2003, to evaluate the readiness of plant personnel to fight fires. The fires were simulated to be in the Unit 1 electrical auxiliary building 60 foot elevation electrical switchgear rooms. Licensee performance was evaluated against criteria listed in Inspection Procedure 71111.05. The inspectors observed the actions of the fire brigade within the plant on the first drill. The second drill was observed from the simulator control room to assess the response of licensed operators to assess command and control, simulated communications with offsite organizations, and manual actions for the fire area required to be performed by the operator actions list. The inspectors observed the licensee use a draft procedure which had been written to address an NRC finding that operator actions to satisfy the fire safe shutdown analysis were not proceduralized and not included in operator training.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors used the guidance in Inspection Procedure 71111.06 to perform inspections of the Unit 1 emergency diesel generator building to verify that the licensee's flood mitigation plans and equipment were consistent with the licensee's design requirements and risk-analysis assumptions. This inspection was performed for both internal and external sources of flooding. The inspection focused on the licensee's design for protecting redundant trains of emergency diesel generators located in this building to verify that adequate mitigation equipment would remain in all flooding scenarios. The inspectors reviewed the Updated Final Safety Analysis Report and the licensee's flooding calculation to evaluate the internal and external flooding design and how current station procedures implemented that design. The inspectors also walked down all three trains in the emergency diesel generator building to identify sources of flooding which were not considered in the licensee's analysis, as well as any missing or degraded flood barriers and flood control features. The following documents were reviewed:

- 0POP04-ZO-0002, "Natural or Destructive Phenomena Guidelines," Revision 22
- Calculation MC-5044, "Flooding Calculation for the Diesel Generator Building," Revision 2

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07A)

a. Inspection Scope

The inspectors observed the setup for performance tests and inspection of the Unit 1 essential cooling water/component cooling water heat exchangers during the refueling outage in March 2003. Review and assessment of the test results against performance criteria and the previous refueling outage test results were conducted. The inspectors also reviewed calculations performed in accordance with Plant Engineering Procedure 0PEP07-EW-0001, “Performance Test For Essential Cooling Water Heat Exchangers,” Revision 6, for all three heat exchangers and compared the results and assumptions to the licensee’s inspection and evaluation process.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (7111.08)

.1 Performance of Nondestructive Examination (NDE) Activities

a. Inspection Scope

The inspector requested and reviewed the NDE records for work that was performed for the current outage at the South Texas Project, Unit 1. The inspector also observed the following visual, liquid penetrant, magnetic particle, and ultrasonic examinations:

System/Component	Examination Method
Pressurizer Seismic Lug	Liquid Penetrant
Main Feedwater Line A Pipe Lugs	Magnetic Particle
Reactor Coolant Pipe Weld	Ultrasonic Examination
Reactor Coolant Pipe Weld	Ultrasonic Examination
Reactor Coolant System Elbow to Pipe Weld	Ultrasonic Examination
Reactor Coolant to Pressurizer Elbow Weld	Ultrasonic Examination
Reactor Coolant to Pressurizer Elbow Weld	Ultrasonic Examination

The inspector reviewed three weld repairs and two indications that were accepted for continued service to determine if they were performed in accordance with ASME Code requirements.

The inspector reviewed licensee NDE and contractor personnel qualification and certification records to determine if NDE personnel were certified to perform the above examinations.

b. Findings

No findings of significance were identified.

.2 Problem Identification and Resolution

a. Inspection Scope

The inspector performed a detailed review of a sample of condition reports initiated within the past 2 years in the area of inservice inspection activities. The review was conducted to ascertain whether plant personnel were identifying performance issues within the inservice inspection program. This review assessed the effectiveness of cause determination and corrective action and the adequacy of the plant personnel's effort to identify transportability and generic issues. The review also assessed the effectiveness of the plant personnel's effort to identify and address programmatic issues within the inservice inspection program.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

The inspectors used the guidance in Inspection Procedure 71111.11 to assess licensed operator requalification training on May 6 and 7, 2003. The inspectors observed two control room simulator scenarios that included a loss of coolant accident (LOCA), a faulted steam generator, and a switchgear fire scenario integrated with the fire brigade. The inspectors observed the performance of Crew 1E for clarity and formality of communications, 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 and protective action recommendations for accuracy and timeliness, reviewed the scenario sequence and objectives, observed the training critique, and discussed crew performance with training instructors.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12 and 71152)

a. Inspection Scope

The inspectors used Inspection Procedures 71111.12 and 71152 to review the circumstances surrounding the failure of a motor-operated valve (MOV) actuator in the residual heat removal (RHR) system in Unit 2. The inspection was conducted between January 25 and April 30, 2003. The inspectors observed the as-found condition of the failed actuator. The results of inspections of other MOV actuators were reviewed and discussed periodically with engineering personnel. The basis and conclusions for operability evaluations for inspection discrepancies were discussed with engineering and operations personnel. Maintenance procedures for MOV actuators were reviewed, along with maintenance and failure histories for these actuators. The following additional documents were reviewed:

- 0PMP05-ZE-0408 “Limitorque Operator Maintenance Type SMB/SB-2 Actuator,” Revision 3
- Information Notices 94-10, 96-48
- Limitorque Type SMB Instruction and Maintenance Manual
- Limitorque Maintenance Update 89-01

b. Findings

Introduction. A finding was identified related to ineffective maintenance practices for MOV actuators that resulted in failure of an RHR valve actuator having potential safety significance greater than Green. This is an unresolved item pending completion of the significance determination process (SDP).

Description. Following a Unit 2 shutdown, on January 25, 2003, the licensee attempted to start Train C RHR to support a cooldown, but the hot leg suction valve (RH-MOV-0060C) failed to open on demand. The licensee eventually determined that the MOV motor became bound and failed. An inspection of the MOV identified that the motor pinion gear set screw had failed to hold the gear in place, and the attempt to open the valve caused the beveled gear to travel along the shaft until it jammed against the declutch mechanism and stopped the motor from turning. The motor pinion gear key had also come loose and was projecting out from the end of the motor shaft, effectively bridging the gap between the motor shaft and the declutch mechanism. Over time, the gear apparently wore against the declutch mechanism until the contact increased motor load and caused the motor to stop, overheat, and fail.

The licensee determined that the motor pinion set screw was not secured properly, and the gear key was not staked in place. Limitorque Maintenance Update 89-01 alerted users to MOV failure mechanisms associated with improperly secured set screws and motor pinion keys and made recommendations to correct the problems. The licensee incorporated this into their site MOV maintenance procedure but did not take actions to assure that keys were staked and set screws were properly secured.

For RH-MOV-0060C, the licensee concluded that the motor pinion gear had not been correctly spot-drilled and secured since 1987. The gear had been found loose in 1993 during Generic Letter 89-10 Program MOV work and had been secured improperly again without reporting the problem in the corrective action program. The 1987 work was performed improperly despite having correct work instructions, and the 1993 work was performed with work instructions provided by a contractor which did not incorporate the vendor recommendations. The licensee had not verified that the contractor procedures were equivalent to the station procedures.

The inspectors noted that the licensee relied extensively on performance monitoring to determine if MOVs needed maintenance. However, this type of failure would not be detected by performance monitoring. The inspectors determined that no routine preventive maintenance activities existed to observe conditions inside the motor pinion compartment on MOV actuators, in order to provide visual detection of this type of problem. Therefore, even though it was likely that these conditions could exist in an actuator for some time before causing a failure, the failure would appear suddenly without opportunity to detect it prior to the failure.

As discussed in Section 4OA2, the licensee determined the extent of condition by promptly inspecting all of the MOVs in both units. These inspections identified numerous discrepancies with how the set screws and keys were secured. Each discrepancy was corrected.

Analysis. The licensee performed an operability evaluation for each discrepancy identified in the actuator inspections. With the exception of the original failure, the licensee concluded that every actuator would have fulfilled its safety function.

The inspectors noted that the licensee’s analysis eliminated most of the population categorically. Valves with a safety function to shut were assumed not to fail because motor pinion movement would push the gear against the motor. Actuators with smaller motors were excluded from failing due to the belief that below a certain torque value the motors could not develop enough thrust to burn up. Protruding keys were eliminated as a failure mechanism based on how much of the key was still in the slot in the shaft at the time of the inspection, without consideration of key movement during subsequent attempted strokes. By selecting design basis safety functions, the licensee did not measure the impact on more routine operations, Technical Specifications, or other activities that would require action by the licensee to address problems. The inspectors and the Region IV Senior Reactor Analyst concluded that expanded criteria should be used to assess the risk associated with potential failures within a few demands.

Therefore, the NRC assessed the licensee's inspection results and judged that seven of the actuators were close to failing in some manner, in addition to the one that actually failed. Six of the actuators had evidence of motor pinion gear movement on the motor shaft, and in one case the key (the design feature to transmit the motor torque to the actuator) was missing. MOVs in this category were:

- B2AFFV7524
- A2RHMOV0060A
- B2RHMOV0060B
- C2RHMOV0060C (actual failure)
- A2SIMOV0008A
- N2CCMOV0374
- C1CVMOV0014
- C2CVMOV0014

Enforcement. Criterion V of 10 CFR Part 50, Appendix B, requires in part that activities affecting quality shall be prescribed by procedures and shall be accomplished in accordance with these procedures. Procedure IP-1.8Q, "Control of Vendor Documents," Revision 6 (the procedure in effect at the time) required the licensee to develop, perform, track, and close out corrective actions for vendor technical bulletins/advisories. Limitorque Maintenance Update 89-01, a document meeting the definition of Vendor Technical Bulletin/Advisory, notified the licensee of the design problem associated with securing the motor pinion set screws and provided recommended actions to correct it. The licensee failed to track actions to ensure that the recommended corrective actions were implemented on applicable MOV actuators. Pending determination of the finding's safety significance, this finding is identified as URI 05000498;499/2003002-01, failure to develop and track corrective actions for vendor technical bulletins/advisories associated with MOV failures.

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) by reviewing selected planned and emergent work items. 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 discussed emergent work issues with work control personnel and reviewed the potential risk impact of these activities to verify that the work was adequately planned, controlled, and executed. The inspectors reviewed seven activities associated with:

- (Unit 2) Train B main steam isolation valve dump valve air leak on-line repair on March 31, 2003 (CR 03-4875, Work Authorization Number (WAN) 249016)
- (Unit 1) Train B reactor coolant pump (RCP) motor lift over operating RHR trains on April 1, 2003 (CR 03-5296)
- (Unit 2) Steam Generator Feedwater Pump 22 trip while performing minor maintenance to replace a redundant power supply on April 26, 2003 (CR 03-7221)
- (Unit 2) Train B emergency diesel generator extended allowed outage on April 30, 2003, to perform 5-year inspections and preventive maintenance items
- (Unit 2) Train B engineered safety feature load sequencer work on April 30, 2003 (CR 03-7225 and WAN 251019)
- (Unit 2) Steam Generator Feedwater Pump 21 Kernel C repair on May 1, 2003 (CR 03-7308)
- (Unit 2) Electrohydraulic control system pulsation damper installation on May 30, 2003 (WAN 252183, Design Change Package 03-4186-13)

b. Findings

.1 RCP Motor Heavy Load Lift

Introduction. A Green NCV was identified for the failure to manage the assessed risk consequences of a heavy load lift over operating RHR trains as prescribed in 10 CFR 50.65(a)(4), maintenance rule.

Description. The inspectors identified on April 1, 2003, during the recent Unit 1 outage at Mode 5, that the licensee removed the RCP 1B motor from containment without following the requirements of Procedure 0PGP03-ZA-0069, “Control of Heavy Loads,” Revision 17. Section 4.9.5 of the procedure requires that “when heavy loads are carried over an RHR train with less than a 10/1 interface lift points safety factor, the RHR train shall be declared INOPERABLE and isolated from the reactor coolant system (RCS) prior to moving the load over the RHR train.” The load path for this specific lift was over RHR Heat Exchangers A and B. RHR Trains A and B were operating at the time (protected trains) and Train C was functional.

The weight of the RCP motor is just under 50 tons. The polar crane rated at 500 tons provides the required safety margin; however, in order to lift the motor out of its cubicle an electric chain hoist and a special lift rig is used. The chain hoist is rated at 55 tons. At that rating the hoist only provides a 5/1 safety factor (commercial grade lifting equipment has a safety factor of 5/1). The special lift rig was built to American National

Standards Institute (ANSI) 14.6 requirements and has an acceptable safety factor. The hoist is an interfacing lift point between the polar crane, the special lift device, and the RCP motor. The licensee stated that the 10/1 requirement did not apply to this lift since this was an "engineered lift." However, Procedure 0PGP03-ZA-0069 does not provide that exception. "Engineered lift" is not defined by industry or the licensee for this application. The American Society of Mechanical Engineers has a similar term for exceeding the design rating of a crane, but these requirements are vaguely followed by the licensee for an "engineered lift." The licensee did follow their procedure for performing required inspections on the chain hoist and special lift rig prior to use.

Generic Letter (GL) 81-07, "Control of Heavy Loads," required licensees to identify which of the load and impact area combinations could be eliminated because of separation and redundancy of safety-related equipment, mechanical stops and/or electrical interlocks, or other site-specific considerations. The licensee, in response, identified RHR piping as a load drop target because it is required for the maintenance of cold shutdown conditions. As an initiating event, shutdown LOCA initiated from the load drop, it could be administratively avoided by implementing separation and redundancy. A drop of an RCP motor on an unisolated RHR heat exchanger could drain the reactor vessel and cause a loss of decay heat removal (DHR). Subsequent failure or unavailability of safety injection or containment sump recirculation would lead to fuel becoming uncovered and eventual damage. Procedure 0PGP03-ZA-0069 developed in regard to the concerns of GL 81-07 adequately mitigated the risks associated with this evolution. The licensee lost focus of this risk mitigating procedure and lifted the RCP 1B motor over RHR Trains A and B without isolating them from the RCS.

<u>Analysis</u>. The preferred way to reduce this risk would be to prevent the accident by either isolating the sections of piping that could be damaged by a load drop from the reactor vessel or by removing the fuel from the reactor vessel. Alternatively, the NRC has accepted implementation of a highly reliable load handling system to reduce the frequency of load drops to a very low value. In this case, the highly reliable load handling system would consist of a single-failure-proof polar crane with either redundant lifting device with a 5/1 safety factor or a single lifting device with a 10/1 safety factor. These lifting devices could be either slings meeting ANSI B30.9 or special lifting devices meeting ANSI N14.6. However, a motorized chain hoist would not be acceptable because chain hoists have several parts and failure of any one of several parts could cause a load drop. Risk could also be managed by ensuring that redundant injection, RHR, and containment recirculation flow paths would be available to provide core cooling, assuming a load drop damaged the RCS or unisolated RHR piping and ensuring that containment integrity was set prior to the lift. However, the licensee would have to perform a risk assessment to ensure that this approach adequately mitigated the risk.

The licensee concluded that performing the lift as an "engineered lift" was equivalent to having a 10:1 rating and, therefore, was equivalent to single failure proof, so RHR did not need to be isolated. The inspectors concluded that the term "engineered lift" was not defined in the licensee's program nor discussed in the licensee's response to GL 81-07 and that the NRC did not approve the conditions of an "engineered lift" as being equivalent to being single failure proof.

The inspectors identified this as a violation of 10 CFR 50.65(a)(4) and consider it more than minor because it affects the initiating events cornerstone by increasing the likelihood of an initiating event. Utilizing Appendix G, shutdown SDP (Phase 1), this is a finding that increases the likelihood that a loss of DHR will occur (MC609, Appendix G, Table 1, pages T-8 to T-10). The Region IV Senior Reactor Analyst conducted a Phase III analysis to determine the risk significance of this event. The finding was determined to be of very low safety significance (Green) based on the low probability of a drop, low probability of a strike on the RHR piping, and the ability of the operators to remotely or manually close MOVs RH-60A, RH-61A, RH-60B, or RH-61B as well as Valves SI-18A or SI-18B to isolate damaged sections in the RHR Trains A or B in the event of an RCP motor drop.

Enforcement. 10 CFR 50.65(a)(4) states "Before performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. The scope of the assessment may be limited to structures, systems, and components that a risk-informed evaluation process has shown to be significant to public health and safety." The licensee failed to manage the increase in risk when the RCP 1B motor was lifted over the operating RHR trains. Specifically, the licensee had developed procedures for mitigating the risk associated with heavy load drops in accordance with commitments made in GL 81-07 which were not followed. Because the failure to manage the associated risk with this heavy load lift is of very low safety significance and has been entered into the licensee's CAP (CR 03-5296), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: 05000498/2003002-02, Failure to Manage the Increase in Risk of the 1B RCP Motor Heavy Load Lift.

.2 Steam Generator Feedwater Pump 22 Trip

Introduction. A Green NCV was identified for the failure to manage the associated risk consequences of performing on-line maintenance on medium risk ranked plant equipment without following station procedures for mitigating the risk as prescribed in 10 CFR 50.65(a)(4), maintenance rule.

Description. On April 26, 2003, Steam Generator Feed Pump 22 tripped while performing minor maintenance to replace a redundant power supply while at power. The event challenged operators, but did not result in a plant transient because the standby startup feed pump was successfully started. Weekend shift maintenance and operations crews did not recognize this work as being a medium trip risk evolution and treat it accordingly. This work should have been characterized as a Medium Risk Evolution and treated in accordance with Procedure 0PGP03-ZA-0090, "Work Process

Program," Revision 24, for Priority 2 work. The maintenance rule requires the licensee to: (1) evaluate the risk of performing maintenance activities, and (2) take appropriate measures to mitigate those risks. Although, in this case, the maintenance and operations crews performed what amounts to a qualitative risk assessment (they knew of the possibility of tripping the pump and possibly the plant), they did not follow station procedures for performing work on risk significant equipment, resulting in relying on standby equipment and tripping a main feedwater pump.

Analysis. The inspectors identified this as a violation of 10 CFR 50.65(a)(4) and considered it more than minor because it affects the initiating events cornerstone by increasing the likelihood of an initiating event. Using SDP Phase 1, this failure to manage the associated risk with this maintenance activity is of very low safety significance (Green).

Enforcement. 10 CFR 50.65(a)(4) states that "Before performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. The scope of the assessment may be limited to structures, systems, and components that a risk-informed evaluation process has shown to be significant to public health and safety." The licensee failed to manage the increase in risk when replacing a redundant power supply on medium risk-ranked equipment while at power without following station procedures for mitigating maintenance risk. Because this issue is of very low safety significance and has been entered into the CAP (CR 03-7221), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: 05000499/2003002-03, Failure to Manage Maintenance Risk with Steam Generator Feedwater Pump 22.

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

a. Inspection Scope

For the nonroutine plant evolutions described below, the inspectors reviewed the licensee's planning documents, attended prejob briefs, and observed personnel performance in the Unit 1 control room and in the field. Since both evolutions involved potentially significant radiological conditions, the inspectors reviewed the as low as reasonably achievable (ALARA) measures and contingency actions.

- On May 14, 2003, the inspectors observed the licensee remove the Unit 1 core barrel from the reactor to facilitate access to the lower reactor head for bottom mounted instrumentation nozzle inspections. The inspectors observed: measures to control access to the reactor containment building, remote monitoring and control of the heavy load, and radiological condition monitoring activities. The inspectors also reviewed plant conditions with operations personnel, since access was limited to important areas of the plant during the lift.

- On May 28 and June 12, 2003, the inspectors observed activities associated with removing and disposing of the highly irradiated Unit 1 bottom mounted instrumentation thimbles. The inspectors assessed the in-vessel handling controls as well as the method of controlling leakage at the seal table, both for radiological and inventory control reasons.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed six operability evaluations conducted by licensee personnel during the report period involving risk-significant systems or components. The inspectors used Inspection Procedure 71111.15 and GL 91-18 to assess the selected operability evaluations. The inspectors evaluated the technical adequacy of the operability determinations, reviewed any compensatory measures, and checked to see that the impacts of other pre-existing conditions were considered, as applicable. Additionally, the inspectors evaluated the adequacy of the problem identification and resolution program as it applied to operability evaluations. Specific operability evaluations reviewed are listed below.

- (Unit 1) Safety-related Battery E1B11 inadvertently shorted across terminals during maintenance on April 10, 2003 (CR 03-5999)

- (Unit 2) Train A essential cooling water pump low differential pressure in required action range on April 22, 2003 (CR 03-6843)

- (Unit 2) Wrong oil used in steam generator Train A power-operated relief valve (PORV) on April 23, 2003 (CR 03-7000)

- (Unit 2) Electrical auxiliary building ventilation damper adjusted improperly on April 29, 2003 (CR 03-7289)

- (Unit 2) Train B incorrect load sequencer switch installed on May 5, 2003 (CR 03-7225)

- (Unit 1) Train C high head safety injection pump breaker failed to close on May 28, 2003 (CR 03-8824)

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors witnessed or reviewed the results of postmaintenance testing for the following five maintenance activities:

- (Unit 2) Train B engineered safety features load sequencer test on April 29, 2003 (CR 03-7225, WAN 251019)
- (Unit 2) Train C essential cooling water pump reference valve test after rebuild on May 12, 2003, 0PSP03-EW-0012, “Essential Cooling Water Pump 2C Reference Values Measurement,” Revision 8 (WAN 222659)
- (Unit 1) Train A fuel handling building ventilation exhaust charcoal replacement on May 15, 2003, 0PSP11-ZH-0009, “EAB and FHB HVAC In-Place Absorber Leak Test,” Revision 18 (WAN 210395)
- (Unit 1) Train C containment spray pump breaker overhaul on May 29, 2003 (WAN 127445)
- (Unit 1) Train A essential cooling water pump discharge MOV thermal overload replacement on June 11, 2003 (WAN 249339)

In each case, the associated work orders and test procedures were reviewed to determine the scope of the maintenance activity and whether the test adequately verified proper performance of the components affected by the maintenance. 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.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

.1 Unit 1 Eleventh Refueling 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 25-26, 2003, and assessed the licensee's compliance with Technical

Specification limits during plant cooldown on March 26-27, 2003. Plant Operating Procedures 0POP03-ZG-0006, “Plant Shutdown from 100% to Hot Standby,” Revision 21, and 0POP03-ZG-0007, “Plant Cooldown,” Revision 33, were 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, DHR, spent fuel pool cooling, containment integrity, and RCS inventory.

Refueling Activities

The inspectors observed portions of core reload activities on March 8-9, 2003, 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.

.2 Unit 1 Bottom Mounted Instrumentation Forced Outage Activities

a. Inspection Scope

On April 12, 2003, the licensee identified leaks from two bottom mounted instrumentation penetrations during a regular inspection of the reactor bottom head. The unit transitioned to a forced outage as the scheduled refueling outage work was completed on April 18, 2003. The inspectors reviewed the major work and weekly outage risk assessments on an ongoing basis to assess them for completeness, accuracy, and adequacy of risk management. The inspectors used Inspection Procedure 71111.20 to conduct frequent plant walkdowns to assess the availability of instrumentation, electrical power, DHR, inventory control, reactivity control, and containment integrity.

Defueling

The inspectors observed the second defueling required for performing bottom mounted instrumentation repair activities from the control room, radiation protection control center, and during containment tours.

Maintaining Plant Conditions

The inspectors reviewed plant conditions and observed selected outage activities throughout the ongoing forced 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, controls for reactivity management, DHR, spent fuel pool cooling, containment integrity, and RCS inventory.

Control of Heavy Loads

The inspectors reviewed the heavy load lift requirements of Procedure 0PGP03-ZA-0069, “Control of Heavy Loads,” Revision 17, to verify that the licensee appropriately implemented the Special Requirements Applicable to the Reactor Containment Building.

The inspectors observed portions of the lift of the reactor head missile shield.

b. Findings

No findings of significance were identified.

.3 Identification and Resolution of Problems

a. Inspection Scope

The inspectors screened CRs that documented problems identified during the Unit 1 outage to assess the threshold for problem reporting and the effect of significance screening, mode restraint screening, operability assessment, and impact on shutdown risk. The inspectors followed up on the licensee’s actions regarding the following issues:

- Canopy seal for reactor head Penetration 78 had pinhole leak repairs on April 7, 2003 (CR 03-3208)

- Overflow of the reactor cavity into spare ventilation ducts on May 17, 2003 (CR 03-8342)
- Refueling water storage tank inadvertently drained to containment due to improper tagout during surveillance testing on May 31, 2003 (CR 03-8973)
- Inadvertent actuation of control room emergency ventilation due to improper tagout on June 2, 2003 (CR 03-9028)

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, recordkeeping, the restoration of standby equipment, the effectiveness of the licensee's problem identification and resolution program, and test equipment accuracy, range, and calibration. The inspectors observed or reviewed the following procedural tests:

- (Unit 1) 0PEP05-ZH-0013, "HVAC Test and Balance Procedure," Revision 2, and 0PSP11-HE-0002, "Control Room Emergency Air Cleanup System Functional Test," Revision 16, on March 25, 2003
- (Unit 2) 0PSP03-DG-0001, "Emergency Diesel Generator 21," Revision 27, on March 25, 2003
- (Unit 1) 0PSP03-SI-0030, "SI Check Valve & Pump Full Flow Operability Test," Revision 14, on April 1 and 2, 2003
- (Unit 2) 0PSP03-CS-0002, "Containment Spray Pump 2B Inservice Test," Revision 9, on April 30, 2003
- (Unit 2) 0PSP11-HE-0002, "Control Room Emergency Air Cleanup System Functional Test," Revision 16, on May 2, 2003
- (Unit 2) 0PSP03-RS-0001, "Monthly Control Rod Operability," Revision 16, and 0PEP02-RS-0001, "Control Rod Axial Repositioning," Revision 3, on June 4, 2003

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the following temporary modifications performed on two feedwater isolation valves, using the guidance contained in Inspection Procedure 71111.23 with respect to design bases, approvals, and tracking. The inspectors reviewed the screening done in accordance with 10 CFR 50.59, updated procedures, and drawings. The inspectors also walked down the temporary modifications.

- TL2-03-5872-2, “On-Line Leak Sealing T-MOD,” on April 15, 2003
- TL2-03-18531-2, “On-Line Leak Sealing T-MOD,” on April 17, 2003

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP2 Alert Notification System Testing (71114.02)

a. Inspection Scope

The inspectors reviewed siren failure trend data and testing records for the second through fourth quarters of 2002 and the first quarter of 2003. The inspectors interviewed licensee emergency preparedness staff members regarding off-site siren and tone alert radio systems to identify changes made to these systems between May 2001 and May 2003 and to determine the adequacy of licensee methods for testing alert and notification systems in accordance with 10 CFR Part 50, Appendix E. The inspectors reviewed Plant General Procedures 0PGP05-ZV-0007, “Prompt Notification System,” Revision 5, and 0PGP05-ZV-0016, “Prompt Notification System Implementing Procedure,” Revision 2, to ascertain notification system testing methodology and requirements. The licensee’s alert and notification system testing program was compared with criteria in NUREG-0654, “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants,” Revision 1, and Federal Emergency Management Agency Report REP-10, “Guide for the Evaluation of Alert and Notification Systems for Nuclear Power Plants.”

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization Augmentation Testing (71114.03)

a. Inspection Scope

The inspectors discussed the status of emergency response organization augmentation systems with licensee staff to identify changes made to primary and backup automatic phone dialing and paging systems between May 2001 and May 2003. The inspectors also reviewed Procedure 0ERP01-ZV-IN03, “Emergency Response Organization Notification,” Revision 9, to determine the licensee’s requirements for staffing emergency response facilities in accordance with the licensee emergency plan and the requirements of 10 CFR Part 50, Appendix E.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors performed an in-office review of Interim Change Notice 20-1 to the South Texas Project Electric Generating Station Emergency Plan, received March 3, 2003, and further discussed the changes with licensee staff on site. Change Notice 20-1: (1) updated company names, (2) revised emergency planning zone population data to the 2002 Census, (3) updated Emergency Alerting System radio station information, (4) further described operation of the Joint Information Center, and (5) eliminated a position from the emergency response organization. The revision was compared to its previous revision, to the criteria of NUREG-0654, “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants,” Revision 1, and to the requirements of 10 CFR 50.47(b) and 50.54(q) to determine if the revision decreased the effectiveness of the plan. The inspectors also reviewed Procedure 0PGP05-ZV-0010, “Emergency Plan Revision,” Revision 6, to determine licensee requirements for making changes to the facility radiological emergency response plan.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope

The inspectors reviewed documents related to the licensee's CAP to determine the licensee's ability to identify and correct problems in accordance with the requirements of 10 CFR 50.47(b)(14) and 10 CFR Part 50, Appendix E. Documents reviewed during the inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors used the guidance in Inspection Procedure 71114.06 to assess two licensed operator drills in the control room simulator on May 6-7, 2003. The inspectors observed the performance of Crew 1E during an evaluated simulator scenario involving a LOCA and Crew 2E during a simulated switchgear fire training session. Operators were evaluated for clarity and formality of communications, correct use of procedures, high risk operator actions, and the oversight and direction provided by the shift supervisor. The inspectors observed the licensee's use of emergency action levels for proper emergency classification and reporting timeliness, reviewed the scenario sequence and objectives, observed the licensee's critique, and discussed crew performance with exam evaluators.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY
Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope

To review and assess the licensee's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, high radiation areas, and very high radiation areas, the inspectors interviewed radiation workers and radiation protection personnel involved in high dose rate and high exposure jobs during Refueling Outage 11. The inspectors discussed changes to the access control program with the outage radiation protection manager. The inspectors also conducted plant walkdowns within the radiologically controlled area and conducted independent radiation surveys of selected work areas. The following items were reviewed and compared with regulatory requirements:

- Area postings and other access controls for airborne radioactivity areas, radiation areas, high radiation areas, and very high radiation areas

- Access controls, radiation work permits (RWP), and radiological surveys involving airborne radioactivity areas and high radiation areas (Seal Replacement on RCPs 1A, 1C and 1D - RWP 2003-1-0092; Reactor Head Bare Head Inspection - RWP 2003-1-0095; Reactor Head Disassembly/Reassembly-Clean O-Ring Groove and Seating Surfaces - RWP 2003-1-0084; and Undervessel Reactor Head Mechanical Support, Inspections, and Walkdowns - RWP 2003-1-0091)

- High radiation area key controls

- Internal dose assessment for exposures exceeding 50 mrem committed effective dose equivalent (no opportunities for review were identified)

- Setting, use, and response of electronic personal dosimeter alarms

- Conduct of work by radiation protection technicians and radiation workers in areas with the potential for high radiation dose and the associated RWPs, radiological surveys, and controls for the work (RCP 1D Seal replacement and reactor head disassembly activities)

- Dosimetry placement when work involved a significant dose gradient

- Controls involved with the storage of highly radioactive items in the spent fuel pool

- Quality Assurance Department Monitoring Reports (MN-02-2-0992, MN-02-2-0935, MN-02-2-1035, MN-02-0-1126, MN-03-0-0031, and MN-03-0-0123) and Health Physics Department Self-Assessment Reports (CR-02-1642, CR-03-2745, and CR-03-2912) involving high radiation area controls and staff performance

- A summary of access controls and high radiation area work practice related corrective action documents written since October 2002 and selected specific examples

b. Findings

.1 Failure to Follow RWP Requirements

Introduction. A self-revealing Green NCV was identified because the licensee failed to follow the requirements of a Technical Specification 6.8.1a required procedure. Specifically, two workers failed to contact health physics personnel prior to breaching a contaminated system.

Description. On March 31, 2003, two workers breached a contaminated system associated with RCP 1B without health physics coverage as required by their RWP 2003-1-0098. This event was discovered when both workers alarmed the personnel contamination monitors when leaving the radiologically controlled area. The highest contamination level was approximately 600 corrected counts per minute, which did not exceed a regulatory limit.

Analysis. The failure to follow RWP requirements is a performance deficiency. The issue was more than minor because it is associated with a cornerstone attribute (program and process) and affected the Occupational Radiation Safety cornerstone objective (to ensure the adequate protection of the worker's health and safety from radiation and radioactive material). The finding involved the failure to control radiological work that was contrary to Technical Specification procedural requirements. When processed through the Occupational Radiation Safety SDP, the finding was found to have very low safety significance because it was not an ALARA issue, there was no overexposure or substantial potential for an overexposure, and the ability to assess dose was not compromised. This event was identified because of an equipment alarm; therefore, the finding was considered self-revealing.

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 7.e.1, requires procedures for the RWP system. Section 4.4.4 of Procedure 0PGP03-ZR-0051, "Radiological Access and Work Controls," Revision 15, required radiation workers to comply with RWP requirements. RWP 2003-1-0098 required radiation protection personnel coverage prior to opening of a pressurized system pressure boundary. The failure to have health physics personnel coverage when breaching a contaminated pressurized system is being identified as a Technical Specification 6.8.1a violation. Because the finding was determined to be of very low safety significance and entered into the licensee's CAP as CR 03-5101, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000498/200302-04).

On April 2, 2003, the licensee identified a second example of a violation involving the failure to follow RWP requirements (see Section 4OA7 for details).

.2 Failure to Perform an Adequate Airborne Survey

Introduction. An NRC-identified Green NCV was identified because the licensee failed to perform an adequate airborne survey during decontamination activities. Specifically, the inspectors identified two examples in which air samplers were not properly positioned to ensure work area airborne radiological conditions were surveyed.

Description. During a tour of the Unit 1 Mechanical Auxiliary Building Decontamination Facility on March 31, 2003, the inspectors noted that the air sampler used to monitor work activities associated with the decontamination of a highly contaminated valve was not positioned between the source and the worker in the direction of the room's negative pressure ventilation and was approximately 12 feet away from the work activity. Loose contamination levels on the valve were as high as 500 rads per hour. The inspectors questioned the placement of the air sampler with a health physics supervisor, who agreed that it would not be a representative airborne sample of the work activities. The job was stopped prior to starting decontamination work.

However, at the inspectors' request, the licensee provided surveys of other decontamination work performed on contaminated components. On October 30 and 31, 2002, four buckets of conoseal parts with loose contamination levels as high as 650 millirad per hour and five buckets of graylock parts with loose contamination levels as high as 450,000 disintegrations per minute were decontaminated in the Unit 2 Mechanical Auxiliary Building Decontamination Facility, respectively. From a review of the survey information, the inspectors determined that the above items were decontaminated in an open area and air samplers were not appropriately placed to be representative of work area radiological airborne conditions.

Analysis. The failure to position air samplers to ensure work area airborne radiological conditions were surveyed is a performance deficiency. The issue was more than minor because it was associated with a cornerstone attribute (program and process) and affected the Occupational Radiation Safety cornerstone objective (to ensure the adequate protection of the worker's health and safety from radiation and radioactive material). The finding involved the failure to control radiological work that was contrary to regulatory requirements. When processed through the Occupational Radiation Safety SDP, the finding was found to have very low safety significance because it was not an ALARA issue, there was no overexposure or substantial potential for an overexposure, and the ability to assess dose was not compromised.

Enforcement. 10 CFR 20.1501a requires, in part, that a licensee make surveys to comply with Part 20 regulations that are reasonable under the circumstances to evaluate the concentrations and quantities of radioactive material and the potential radiological hazards. 10 CFR 20.1003 defines survey as an evaluation of the radiological conditions and potential hazards incident to the production, use, transfer, release, disposal, or presence of radioactive material or other sources of radiation. When appropriate, such an evaluation includes a physical survey of the location of radioactive material and measurements or calculations of levels of radiation, or concentrations or quantities of radioactive material present. Under the circumstances, a survey would have been necessary to verify compliance with 10 CFR 20.1201, "Occupational Dose Limits for Adults." The failure to position air samplers to ensure work area airborne radiological conditions were surveyed is a violation of 10 CFR 20.1501a. Because the finding was determined to be of very low safety significance and entered into the licensee's CAP as CR 03-5121, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000498;499/200302-05).

On November 18, 2002, the licensee identified a second example of a violation for the failure to perform a survey (see Section 4OA7 for details).

.3 Failure to Inform a Worker of the Radiological Conditions in the Work Area

Introduction. A self-revealing Green NCV was identified because the licensee failed to inform a radiation worker of the radiological conditions in the work area. Specifically, a worker failed to get briefed on the work area radiological conditions at the Unit 1 health physics access point. Additionally, a health physics technician providing job coverage did not inform the worker of the conditions.

Description. On April 3, 2003, two workers were assigned the task of obtaining measurements associated with the Unit 1 reactor head conoseal Penetration 78. However, one of the two workers, who was properly briefed on the radiological conditions for the fuel movement task (RWP 2003-1-0055), was not briefed on the radiological conditions of conoseal Penetration 78. Electronic dosimeter setpoints for RWP 2003-1-0055 were 40 mrem dose accumulated and 250 mrem dose rate. The health physics technician providing job coverage opened the lock for the cable securing the Unit 1 reactor head shroud doors but did not verify the radiological conditions in the work area or inform the worker of the conditions. From a review of the survey data, the inspectors determined that the general work area radiation levels were as high as 400 millirem per hour. While the worker (who was assigned the additional task of fuel movement) was obtaining the size measurements of conoseal Penetration 78, his electronic dosimeter alarmed on dose rate. At the direction of the health physics technician, the workers secured the area and exited the reactor containment building.

Analysis. The failure to inform a worker of the radiological conditions in a work area is a performance deficiency. The issue was more than minor because it was associated with a cornerstone attribute (program and process) and affected the Occupational Radiation Safety cornerstone objective (to ensure the adequate protection of the worker's health and safety from radiation and radioactive material). The finding involved the failure to control radiological work that was contrary to regulatory requirements. When processed through the Occupational Radiation Safety SDP, the finding was found to have very low safety significance because it was not an ALARA issue, there was no overexposure or substantial potential for an overexposure, and the ability to assess dose was not compromised. This event was identified because of an equipment alarm; therefore, the finding was considered self-revealing.

Enforcement. 10 CFR 19.12 requires that all individuals who in the course of employment are likely to receive in a year an occupational dose in excess of 100 millirem shall be kept informed of the transfer or use of radioactive material and in precautions to minimize exposure. The failure to inform a worker of the radiological conditions is a 10 CFR 19.12 violation. Because the finding was determined to be of very low safety significance and entered into the licensee's CAP as CR 03-5428, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000498/200302-06).

3. SAFEGUARDS
Cornerstone: Physical Protection (PP)

3PP4 Security Plan Changes (71130.04)

a. Inspection Scope

The inspectors performed an in-office review of the following Physical Security Plan and Training and Qualification Plan changes to determine if they decreased the effectiveness of the Physical Security Plan and Training and Qualification Plan, respectively, and to determine if requirements of 10 CFR 50.54(p) were met:

- Physical Security Plan, Revision 16A, dated April 21, 2003, involved several administrative updates to the Physical Security Plan such as: reflecting changes in titles of management positions, rewording terminology to comply with the Access Authorization Order, and substituting the reference to the use of shotguns (12-gauge) with handguns and/or rifles.

- Security Personnel Training and Qualification Plan, Revision 6A, dated April 21, 2003, involved rewording terminology to comply with the Access Authorization Order, and substituting the reference to the use of shotguns (12-gauge) with handguns and/or rifles.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA1 Performance Indicator Verification (71151)

.1 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors reviewed CAP records involving locked high radiation areas (as defined in Technical Specification 6.12.2), very high radiation areas (as defined in 10 CFR 20.1003), and unplanned exposure occurrences (as defined in NEI (Nuclear Energy Institute) 99-02) for the past 12 months to confirm that these occurrences were properly recorded as performance indicators. Radiologically controlled area entries with exposures greater than 100 millirem within the past 12 months were reviewed, and selected examples were examined to determine whether they were within the dose projections of the governing radiation exposure permits. Whole-body counts or dose estimates were reviewed if the radiation worker received a committed effective dose equivalent of more than 100 millirem. Where applicable, the inspectors reviewed the summation of unintended deep dose equivalent and committed effective dose equivalent to verify that the total effective dose equivalent did not surpass the performance indicator threshold without being reported.

b. Findings

No findings of significance were identified.

.2 Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences

a. Inspection Scope

The inspectors reviewed radiological effluent release program corrective action records, licensee event reports (LERs), and annual effluent release reports documented during the past four quarters to determine if any doses resulting from effluent releases exceeded the performance indicator thresholds (as defined in NEI 99-02).

b. Findings

No findings of significance were identified.

.3 Emergency Preparedness Performance Indicator Review

a. Inspection Scope

The inspectors sampled licensee submittals for the performance indicators listed below for the second, third, and fourth quarters 2002 and first quarter 2003. The definitions and guidance of NEI 99-02, “Regulatory Assessment Indicator Guideline,” Revision 2, were used to verify the licensee’s basis for reporting each data element in order to verify the accuracy of performance indicator data reported during the assessment period.

Emergency Preparedness Cornerstone

- Drill and Exercise Performance
- Emergency Response Organization Drill Participation
- Alert and Notification System

The inspectors reviewed a 100 percent sample of drill and exercise scenarios, licensed operator simulator training sessions, notification forms, and attendance and critique records associated with training sessions, drills, and exercises conducted during the verification period. The inspectors reviewed selected emergency responder rosters, qualification, training, and drill participation records. The inspectors reviewed siren test and maintenance records and procedures. The inspectors also interviewed licensee personnel responsible for collecting and evaluating performance indicator data.

b. Findings and Observations

No findings of significance were identified. However, the inspectors determined that 14 offsite notification opportunities associated with operator requalification simulator training conducted during the second quarter 2002 were inappropriately included in the drill and exercise performance indicator because the as-run scenario did not include a formally assessed classification included in the drill and exercise performance indicator. NEI 99-02, Revision 2, stated, in part, “Performance indicator statistics from operating shift simulator training evaluations may be included in this indicator only when the scope requires classification.” NEI 99-02, Revision 2, also stated that “Evaluated simulator training evolutions that contribute to DEP [drill and exercise performance] statistics may be considered as opportunities for key ERO [emergency response organization] member participation and may be used for this indicator. The scenarios must at least contain a formally assessed classification . . .” A feedback form has been initiated to clarify the intent of the NEI guidance regarding opportunities generated during operator training.

.4 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 2002:

- 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.

.5 Mitigating Systems Performance Indicator Review

a. Inspection Scope

The inspectors reviewed performance indicator data for the period from the second quarter of 2002 through the second quarter of 2003 to assess the accuracy and completeness of the indicator reporting. The inspectors used NEI 99-02, “Regulatory Assessment Performance Indication Guideline,” Revision 2, as guidance for this inspection. The following performance indicators were reviewed for both units:

- Safety system functional failures

- Safety system unavailability for the following systems:

  Emergency power
  High head safety injection
  Auxiliary feedwater
  Residual heat removal

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 MOV Actuator Failure on Demand

a. Inspection Scope

The inspectors performed a detailed review of the licensee's identification and resolution of a failure of an MOV, documented in CR 03-1341. The licensee's extent of condition assessment, operability assessments, and prioritization methodology were reviewed and discussed with engineering, operations, and risk assessment personnel. Maintenance procedures for MOV actuators were reviewed, along with maintenance and failure histories for these actuators. The inspectors evaluated the CR against the requirements in the licensee's CAP and 10 CFR Part 50, Appendix B.

b. Findings and Observations

This issue is discussed in detail in Section 1R12 above. No findings in the area of identification and resolution of problems were identified.

The inspectors noted that upon identifying the cause of the failure of an MOV actuator, the licensee made a prompt effort to determine the extent of condition and correct any discrepancies that were identified on the spot. The original plan to perform a risk-informed sample was appropriately modified to include all MOV actuators when multiple discrepancies were identified during early inspections. Over 320 actuators were inspected, and corrected as appropriate, within 3 months of the original failure.

.2 Procedure Revision and Review Effectiveness

a. Inspection Scope

The inspectors used Inspection Procedure 71152 to review the licensee's problem identification and resolution regarding an apparent negative trend in the procedure revision and review process. The following CRs were reviewed that indicated that the procedure review process was less than adequate:

02-6385	02-8737	02-9857	02-12015	03-3907
03-3929	03-5102	03-4794	03-6128	

The inspectors also held discussions with maintenance personnel and personnel in the procedure group.

b. Findings and Observations

No findings in the area of identification and resolution of problems were identified.

The inspectors observed an apparent negative trend in the procedure revision and review process. One specific procedure error caused the lifting of a pressurizer PORV. Although the licensee has taken corrective actions, these did not resolve the problem, and procedure errors have continued. The inspectors noted that the licensee has been slow in responding to this negative trend and implementing effective corrective action. An earlier opportunity to take action was missed when the trend was identified in March 2003 during a self-assessment. However, because this self-assessment was documented in a CR designated as a “condition not adverse to quality,” it was not made known to responsible parties and no corrective actions were developed. The licensee is currently investigating this trend under CR 03-6128 in response to two event review team investigations for plant events that occurred after the self-assessment document was issued in March 2003 (CR 03-3929 and 03-4794).

.3 Emergency Preparedness Self-Assessments

a. Inspection Scope

The inspectors selected two assessment reports for detailed review, Quality Audit Report 2002-002 and Quality Audit Report 2003-004. The assessment reports were associated with an annual review of onsite and offsite emergency preparedness program elements. The reports were reviewed to ensure that the full extent of the issues had been identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. The inspectors reviewed the CRs against the requirements of Procedure 0PGP03-ZX-0002, “Condition Reporting Process,” Revision 25.

b. Findings and Observations

There were no findings identified associated with the reviewed sample. However, the inspectors determined that the audit reports did not always clearly communicate the issues of concern. For example, Audit 2003-004 stated that the work scheduling process placed a low priority on work in the emergency operations facility. However, the inspectors determined from interviews with the lead auditor that the work scheduling process was considered adequate and that the emergency preparedness staff did not consistently communicate work priorities to work planners and had not always maintained an awareness of the needed work.

4OA3 Event Followup (71153)

.1 Multiple Pressurizer PORV Lifts During Solid Plant Operation

a. Inspection Scope

The inspectors conducted a followup inspection for a shutdown event in which multiple pressurizer PORV lifts occurred in a short span while Unit 1 was operating in a solid water condition. Discussions were held with the shift supervisor and operations manager immediately after the event on March 26, 2003. The inspectors interviewed an instrumentation and controls work group supervisor, outage supervisors, the Unit 1 Operations Manager, and the control room operators that were on watch during the event during the subsequent 2-week period. This issue is in the licensee's CAP as CR 03-4704. The following documents were reviewed and used as criteria for evaluating operators' response to this event:

- 0POP04-RP-0005, "Cold Overpressure Mitigation System Actuation or Failure," Revision 6
- 0POP04-RC-0002, "Reactor Coolant Pump Off Normal," Revision 20
- 0POP03-ZG-0007, "Plant Cooldown," Revision 37

In addition, the inspectors reviewed Procedure 0PMP08-SP-0001, "RPS/ESF System Normalization," Revision 8, and inspected the normalization test panel installation and the normalization control log.

b. Findings

Introduction. A finding was identified for inappropriate operator response to an event with multiple pressurizer PORV lifts during operations in a water solid condition. The event was caused, in part, because operators did not understand and control the impact of restoration of power to an instrumentation panel and did not understand the interactions between the normal controller and the cold overpressure mitigation system. This is an unresolved item pending completion of a significance determination.

Description. On March 26, 2003, shortly after shutting down, Unit 1 was in Mode 5, solid plant condition at 180°F and 370 psig, running two RCPs for crudburst cleanup. Two trains of RHR were removing decay heat, with pressure control being maintained by the letdown pressure control valve. Power was removed to a distribution panel which deenergized pressurizer pressure Channel 458. Subsequently, some RCS instrumentation was "normalized" (given test inputs at approximately normal operating values to permit testing). When power was restored to the distribution panel, pressurizer PORV 655A lifted and had to be manually shut. Pressure rapidly dropped from 370 psig to 62 psig, requiring operators to secure both running RCPs due to low seal differential pressures. Shortly after that, pressure increased to the 465 psig setpoint for the cold overpressure mitigation system, and PORV 656A opened twice in succession before operators closed it. This pressure increase was believed to be caused by slow response by the letdown pressure control valve and reduced cooling due to securing RCPs. Operators then attempted to place PORV 655A in a normal lineup (automatic), but it opened immediately, so it was reclosed. The licensee identified the problem and operators restored PORV 655A to an operable condition approximately 6 hours after the event.

Through interviews, the inspectors determined that the transient was too rapid for the operators to consult procedures before taking action. The first action to manually close PORV 655A was appropriate based on having no valid reason for it to actuate. Securing the running RCPs was also appropriate due to exceeding the seal pressure parameters. However, operators did not effectively monitor the resulting pressure trend, and thus failed to recognize that PORV 656A opened on a valid cold overpressure condition. Control board annunciators alarmed to support a conclusion that this actuation was valid, but the operator did not look at the annunciators before taking action. The action to close this valve was inappropriate based on the plant conditions. The PORV was closed and then reported as closed, at which time the shift supervision recognized that action was inappropriate and appropriately ordered the valve be placed back in automatic. After a few minutes, pressure control was regained and pressure stabilized. The Unit Supervisor then inappropriately ordered that PORV 655A be returned to automatic without identifying why the valve originally opened. He believed it had opened on an electrical transient caused by re-energizing the instrument panel. The operator who placed PORV 655A in automatic did not notice that the pressurizer pressure controller had a full demand signal that caused the valve to reopen as soon as it was placed in automatic. He promptly returned it to a closed position.

The sequence of events that caused PORV 655A to open included:

- Distribution panel DP-1204 was deenergized, causing pressurizer pressure Channel 458 to fail low. This provided a block signal that prevented PORV 655A from responding to any demand from the pressurizer pressure controller.

- The plant was filled to a water solid condition, using the letdown pressure control valve to balance water inventory and thus plant pressure. In these conditions, small changes in the volume of the RCS cause large pressure changes.

- Test signals to simulate at-power readings were installed for various primary plant instruments to facilitate surveillance testing (referred to locally as “normalizing.”) These included all pressurizer pressure channels, although Channel 459 remained failed low.

- Instrument Panel DP-1204 was re-energized.

The licensee determined that the test signals inserted for one or more of the pressurizer pressure instruments was slightly higher than normal. This caused the pressure controller to develop an error signal that gradually increased until full demand was reached. This would have caused PORV 655A to open, but the deenergized/failed low channel blocked that actuation. A control room annunciator was received, indicating the PORV open demand existed during the previous shift but was not understood or discussed with the oncoming shift. This represented a prior opportunity to identify and correct the problem. When the instrument was re-energized, the block signal cleared, allowing the controller to open the PORV. Since the pressure channels were using a test signal, opening PORV 655A did not cause the condition to clear, so the PORV would not have reclosed without operator action.

Operators did not fully understand the design and operation of the pressurizer pressure controller. This deficiency has been identified in three previous events involving pressurizer PORV lifts this year, documented in NRC Inspection Report 05000498/2002006;05000499/2002006, but planned corrective actions have not yet been fully implemented. During this event, operators on two shifts failed to recognize and understand that a full PORV open demand existed prior to the event. Some operators interviewed did not understand that both the cold overpressure mitigation system and the pressurizer pressure controller could open a PORV with this equipment lineup. The procedure for shutting down and cooling down the plant did not specify the condition of the pressurizer pressure controller, and the procedure for installing normalization blocked all automatic actuation signals except those associated with the pressurizer pressure controller. The inspectors concluded that it was inappropriate to have the pressurizer pressure controller in automatic with test signals inserted to simulate normal operating pressure with actual plant pressure well below normal operating pressure.

Analysis. The function of the cold overpressure mitigation system is to prevent overpressurizing the RCS in a cold plant condition. In the plant conditions at the time of the event, the low pressure piping of the RHR system was the limiting component. The cold overpressure mitigation system was intended to open a PORV to prevent rupturing the RHR piping, causing a shutdown LOCA. During a brief period, estimated by the licensee as being approximately 5 seconds, operators removed both PORVs from an automatic functional status when a valid actuation was in progress. By the time one PORV was returned to automatic, the automatic demand had cleared. During this time, two RHR suction relief valves were available. While these relief valves are not credited in Technical Specifications, they are adequately sized to satisfy the Technical Specifications for this function. Therefore, overpressure protection was available throughout this event.

Inappropriate operator performance in responding to this event was considered more than minor because it impacted the initiating events cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations. The inadequate abnormal operating procedure was more than minor because it impacted the mitigating systems cornerstone objective in that the quality of procedures for responding to events ensures the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

Enforcement. The licensee identified in their event review that Abnormal Operating Procedure 0POP04-RP-0005, “Cold Overpressure Mitigation System Actuation or Failure,” Revision 6, was inadequate because it did not contain actions to respond to a valid actuation of the cold overpressure mitigation system. The existing steps addressed only invalid actuations. This violation is dispositioned in Section 4OA7 as a licensee-identified NCV. No other violations were identified. Pending determination of the finding's safety significance, this finding is identified as URI 05000498/2003002-07, Inappropriate Operator Response to PORV Lifts during Solid Plant Operations.

.2 (Closed) LER 05000499/2003001-00 RHR Train Inoperable for Longer Than Allowed by Technical Specifications

Description. On January 25, 2003, with Unit 2 cooling down for forced outage work, Train C RHR pump suction Valve RH-MOV-0060C failed while opening. The motor failed because the motor pinion gear came loose and bound against actuator internals. This issue is described in detail in Sections 1R12 and 4OA2 of this report. The licensee concluded that this valve had been inoperable since January 2, 2003, when the valve had last successfully operated. The licensee evaluated the cause and attempted to determine the extent of condition through a review of maintenance records. However, the licensee was unable to make any clear determinations from records, so MOV actuators were inspected. All safety-related MOVs and most other MOVs in both units were inspected in the subsequent 3-month period. Any deficiencies were noted and corrected.

Analysis. Having one train of RHR inoperable was determined to be of very low safety significance (Green). The Phase 2 SDP Notebook for South Texas Project credits the RHR pumps only for a steam generator tube rupture. The South Texas Project design uses the RHR system for the shutdown cooling function only and uses the low head safety injection system for injection and recirculation functions. The Phase 2 assessment determined this issue to have very low safety significance for the time Unit 2 was operated at power with one train of RHR inoperable. For the time spent in Mode 3 (hot standby), this issue screens as Green in a Phase 1 SDP.

Enforcement. Technical Specification 3.5.6 requires RHR to be operable in Modes 1, 2, and 3 and permits operation for 7 days with one train inoperable, but does not permit an increase in operating modes. The licensee operated Unit 2 in Modes 1, 2, and 3, including increasing the mode of operation with one train of RHR inoperable, for 23 days. This violation is dispositioned in Section 4OA7 as a licensee-identified NCV.

The LER was reviewed by the inspectors and no findings of significance were identified. The licensee documented the failed equipment and MOV inspection findings in CR 03-1341. This LER is closed.

4OA5 Other Activities

.1 Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (Temporary Instruction 2515/150)

a. Inspection Scope

The inspectors used the guidance in Temporary Instruction 2515/150 to assess the licensee's efforts to identify potential circumferential cracking of reactor pressure vessel head penetration nozzles in accordance with NRC Bulletin 2002-02. This unit was a low-susceptibility plant (Bin 4). The inspectors observed the licensee's visual inspection of the reactor head, reviewed video tapes of the inspection results, and compared them to the inspection records. The inspectors had previously reviewed the training and qualifications of the NDE inspectors and evaluators during the inspection of Unit 2 under Temporary Instruction 2515/145. The inspectors discussed the examination results with the NDE inspectors and evaluators.

b. Findings and Observations

The licensee was able to conduct a 360-degree visual inspection of all reactor vessel head penetration nozzles and no leaks were identified. Minor boron deposits were removed or cleaned. These deposits originated from above the reactor pressure vessel penetrations. The training, procedures, and equipment used were adequate to ensure detection of leaks or corrosion.

The licensee performed a visual examination of the upper side of the reactor head without removing insulation. The insulation was a metal-canned type set in three tiers on a metal frame, with a gap of 2 inches or more between the insulation and the head. The control rod drive mechanism nozzles extended up through the insulation, terminating in a threaded connection to the control rod drive mechanism housing with a canopy seal weld.

The licensee conducted a VT-2 bare metal reactor head inspection in Unit 1 from March 26 through April 1, 2003. The inspections were performed by qualified VT-2 NDE inspectors with experience conducting a similar inspection at another reactor site using the same equipment. The inspections were performed using high-quality video cameras mounted on a remotely piloted crawler, where accessibility existed. In areas where the canned insulation or structures inhibited access, a boroscope-type video probe was used. The inspection was adequate to be able to detect the primary water stress corrosion cracking phenomenon because the licensee was able to inspect 360 degrees around all nozzle penetrations and was able to detect and assess very small quantities of boron. A nitrogen hose was used to blow away moveable debris and boron. The small quantity of adherent boron was sufficiently thin such that it did not prevent examination of the head material for evidence of corrosion.

The reactor head was free of leaks and without any major boron deposits. The head had never been cleaned prior to this examination, so there was a layer of dust and minor construction debris (e.g., small pieces of lockwire, metal flakes from machining). Some nozzle penetrations were observed to have a boron residue around the penetration extending upwards. These were judged by the licensee to have leaked from elsewhere, as no evidence of pressurized spraying (popcorn-like boron) existed near the nozzle. None of the areas of boron accumulation prevented the licensee from examining the condition of the reactor head metal, and none exhibited any head corrosion of significance. No repairs were required as a result of this inspection.

The licensee documented the results of the inspection in Reports RHVT2-2003-001 and RHVT2-2003-002. The licensee retained video records for future comparison. Some cleaning of the head area was later performed to remove dust and debris as well as cleaning up boron deposits.

.2 (Closed) Unresolved Item 05000499/2002006-02: Failure to follow procedures to ensure gas accumulation in the reactor head was vented.

Introduction. A Green NCV was identified for failure to follow procedures.

Description. On February 20, 2003, operators drained water in the RCS to a level that was below the top of the reactor head in order to perform head vent valve maintenance. Level was being maintained using the magnetic sight glass, with heated-junction reactor vessel water level probes as a backup indication. After draining to the new level was completed, the reactor head vent path was isolated to facilitate replacing one of the reactor head vent valves. Over the course of the next 20 hours, operators periodically drained water from the RCS to maintain the water level indicated on the magnetic sight glass at the desired level. However, when the operators noted that Probe 2 indicated “dry,” they realized that gas had accumulated, causing the sightglass to indicate falsely high. Accumulated nitrogen in the reactor head displaced about 4000 gallons of reactor coolant.

Assessment. This issue affected the Initiating Events cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions (inventory control) during shutdown operations due to human performance. This issue represents a loss of control as defined in Appendix G (Shutdown SDP) to Manual Chapter 0609. This issue was documented in NRC Inspection Report 05000498/2002006; 05000499/2002006 as an unresolved item pending NRC assessment of the risk significance of this issue.

This finding, which was considered to be more than minor because it involved the actual consequence of a significant draindown of RCS inventory, was reviewed under Manual Chapter 0609, Appendix G, using the worksheet entitled, "PWR Cold Shutdown and Refueling Operation RCS Open and Refueling Cavity Level <23 feet." A Phase II analysis is required for findings that increase the likelihood of a loss of RCS inventory and, because the event qualified as a loss of control as defined by Appendix G, a quantitative evaluation must be accomplished.

The senior reactor analyst evaluated the risk associated with the finding. The program office is developing a Phase II risk tool to evaluate events and conditions occurring during shutdown. This document remains in draft status and was not used to evaluate this event.

In an attempt to quantify the risk associated with this event, the analyst made the following assumptions/observations:

(1) During the time that the RCS was being inadvertently drained, one instrument (reactor vessel level indication system) was unaffected by the finding and was providing reliable indication. However, this instrument provided indications of gross changes in level and could not be used initially to detect the slow drop in level caused by the expanding gas bubble.

(2) The primary level indication (magnetic sightglass) was indicating a misleading level because it did not sense the presence of a bubble in the reactor vessel. If the draindown had continued to below the top of the loops, the bubble would have vented to the pressurizer and the sightglass would have accurately indicated reactor vessel level.

(3) The draindown was proceeding at a very slow pace (20 hours to void 4000 gallons), was controlled by the operators, and was governed by the rate at which gas was being liberated in the vessel.

(4) DHR would not have been degraded until level in the vessel had decreased to below midloop conditions. This would not have occurred until several hours after the sightglass became a reliable indicator of level (actually much longer since the level decrease would have been slowed by the gas venting through the pressurizer).

(5) The operators were closely monitoring both level indications and would have seen indications of a level problem in both indications with ample time to take appropriate corrective actions.

Based on the above considerations, the analyst found that the level of operator and equipment failures necessary to cause core damage was essentially identical to the base risk case and that a quantification of the risk attributable to the performance issue was not readily achievable. The analyst concluded that the event had very low risk significance (Green).

Enforcement. A violation was identified for failure to follow Plant Operating Procedure 0POP03-ZG-0007, “Plant Cooldown,” Revision 34, which required the head vent valves to be open in this plant condition in order to vent gases evolved near the core from collecting in the reactor head area. This was a procedure required by Technical Specification 6.8.1 and Regulatory Guide 1.33. Based on a significance determination of Green, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000499/2003002-08). This issue was entered into the licensee’s CAP under CRs 03-2751 and 03-3443.

4OA6 Meetings, including Exit

.1 Exit Meeting Summary

The results of the radiation safety inspection were presented to Mr. G. Parkey, Vice President, Generation, and other members of licensee management at the conclusion of the inspection on April 4, 2003.

The results of the in-office security inspection were presented to Mr. Skip Cooper, Security Manager, during a telephonic exit conference call on May 5, 2003.

The results of the emergency preparedness inspection were presented to Mr. G. Parkey, Vice President, Generation, and other members of licensee management at the conclusion of the inspection on May 8, 2003.

The results of the resident inspection were presented to Mr. G. Parkey, Vice President, Generation, and other members of licensee management on July 1, 2003.

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.

.2 Annual Performance Assessment Meeting

On March 24, 2003, the NRC held a public meeting at the Bay City Civic Center to discuss the results of the NRC’s annual assessment of performance at South Texas Project. The meeting was led by Mr. A. Howell, Director, Reactor Projects, Region IV. Mr. G. Parkey, Vice President, Generation, and members of his staff attended.

4OA7 Licensee Identified Violations

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

- Technical Specification 6.12.1 requires high radiation areas to be conspicuously posted. On October 31, 2002, a high radiation area was not posted for approximately 3 hours after radiography was completed in Unit 2 Reactor Containment Building Pressurizer Cubical Room 310. General radiation levels were as high as 180 millirem per hour. This event was documented in the licensee's CAP as CR 02-16056. This finding is only of very low safety significance because it was not an ALARA issue, there was no overexposure or substantial potential for an overexposure, and the ability to assess dose was not compromised.

- 10 CFR 20.1501a requires, in part, that a licensee make surveys that are reasonable under the circumstances to evaluate the extent of radiation levels and the potential radiological hazards. However, on November 18, 2002, Room 110 in the Unit 1 Mechanical Auxiliary Building had elevated general area radiation levels as high as 15 Rem per hour for approximately 24 hours before it was identified. This event was documented in the licensee's CAP as CR 02-17157. This finding is only of very low safety significance because it was not an ALARA issue, there was no overexposure or substantial potential for an overexposure, and the ability to assess dose was not compromised.

- Technical Specification 6.8.1a requires procedures for the RWP system. Section 4.4.4 of Procedure 0PGP03-ZR-0051, "Radiological Access and Work Controls," Revision 15, required radiation workers to comply with RWP requirements. However, on April 2, 2003, two workers removed a reactor cavity light from the reactor cavity without health physics coverage as required by their RWP (RWP 2003-1-0070). This issue was documented in the licensee's CAP as CR 03-5333. This finding is only of very low safety significance because it was not an ALARA issue, there was no overexposure or substantial potential for an overexposure, and the ability to assess dose was not compromised.

- Technical Specification 6.8.1 and Regulatory Guide 1.33 require that the licensee have procedures for responding to abnormal operating conditions. Abnormal Operating Procedure 0POP04-RP-0005, "Cold Overpressure Mitigation System Actuation or Failure," Revision 6, was inadequate because it did not contain actions to respond to a valid actuation of the cold overpressure mitigation system. This was identified in the licensee's CAP as CR 03-4704. This violation is of very low safety significance because operators promptly recognized that they had isolated the remaining cold overpressure relief valve and restored it to automatic operation within seconds; non-Technical Specification relief valves were available to prevent overpressurization during the event described in Section 4OA3.1.

- Technical Specification 3.5.6 requires RHR to be operable in Modes 1, 2, and 3 and permits operation for 7 days with one train inoperable, but does not permit an increase in operating modes. The licensee operated Unit 2 in Modes 1, 2, and 3, including increasing the mode of operation, with one train of RHR inoperable, for 23 days. This licensee-identified NCV was reported in LER 05000499/2003001 and is documented in Section 4OA3.2.

Supplemental Information

KEY POINTS OF CONTACT

Licensee Personnel:

R. Aguilera, Supervisor, Radiation Protection
M. Berg, Manager, Operating Experience Group
K. Coates, Manager, Maintenance
J. Cook, Supervisor, Engineering Specifications
J. Crenshaw, Manager, Systems Engineering
R. Gangluff, Manager, Chemistry
C. Grantom, Manager, PRA
E. Halpin, Manager, Plant General
S. Head, Manager, Licensing
T. Jordan, Vice President, Engineering and Technical Services
W. Jump, Manager, Training
A. Kent, Manager, Testing/Programs
A. Khosla, Liaison, Co-owner
J. Langston, Acting Radiation Protection Manager
M. Lashley, Test Engineering Supervisor
D. Leazar, Manager, Fuels and Analysis
M. McBurnett, Manager, Quality and Licensing
F. Mallan, Director, Business Services
M. Meier, Manager, Generation Station Support
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A. Morgan, Supervisor, Emergency Preparedness
M. Murray, Supervisor, System Engineering
G. Parkey, Vice President, Generation
J. Phelps, Manager, Operations Division
K. Richards, Director, Outage
D. Rencurrel, Manager, Operations
W. Russell, Supervisor, Procedure Group
R. Savage, Senior Staff Specialist
P. Serra, Manager, Plant Protection
J. Sheppard, Vice President & Assistant to the President & CEO
D. Stillwell, Supervisor, Configuration Control and Analysis
S. Thomas, Manager, Plant Design Engineering
D. Towler, Manager, Quality
J. Winters, Systems Engineering

NRC:

T. Scarbrough, Mechanical Engineering Branch, NRR

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000498;499/2003002-01	URI	Failure to develop and track corrective actions for vendor technical bulletins/advisories associated with MOV failures (Section 1R12)
05000498/2003002-02	NCV	Failure to manage the increase in risk of the RCP 1B motor heavy load lift (Section 1R13)
05000499/2003002-03	NCV	Failure to manage maintenance risk with steam generator Feedwater Pump 22 (Section 1R13)
05000498/2003002-04	NCV	Failure to follow RWP requirements (Section 2OS1)
05000498;499/2003002-05	NCV	Failure to perform an adequate airborne survey (Section 2OS1)
05000498/2003002-06	NCV	Failure to inform a worker of the radiological conditions in the work area (Section 2OS1)
05000498/2003002-07	URI	Inappropriate Operator Response to PORV Lifts During Solid Plant Operations (4OA3.1)
05000499/2003002-08	NCV	Failure to follow a procedure required by Technical Specification 6.8.1 and Regulatory Guide 1.33 to ensure gas accumulation in the reactor head was vented (Section 4OA5.2)

Closed

05000498/2003002-02	NCV	Failure to Manage the Increase in Risk of the 1B RCP Motor Heavy Load Lift (Section 1R13)
05000499/2003002-03	NCV	Failure to Manage Maintenance Risk with Steam Generator Feedwater Pump 22 (Section 1R13)
05000498/2003002-04	NCV	Failure to follow RWP requirements (Section 2OS1)
05000498;499/2003002-05	NCV	Failure to perform an adequate airborne survey (Section 2OS1)
05000498/2003002-06	NCV	Failure to inform a worker of the radiological conditions in the work area (Section 2OS1)

05000499/2003001-00	LER	Inoperable Residual Heat Removal Train (Section 4OA2)
05000499/2002006-02	URI	Apparent violation for failure to follow a procedure required by Technical Specification 6.8.1 and Regulatory Guide 1.33 to ensure gas accumulation in the reactor head was vented (Section 4OA5.2)
05000499/2003002-08	NCV	Failure to follow a procedure required by Technical Specification 6.8.1 and Regulatory Guide 1.33 to ensure gas accumulation in the reactor head was vented (Section 4OA5.2)

LIST OF DOCUMENTS REVIEWED

Section 1R08: Inservice Inspection Activities (7111.08)

OPEP10-ZA-0004	"UT/ISI General Ultrasonic Examination," Revision 0
OPEP10-ZA-0012	"PT/ISI Color Contrast Solvent Removable Liquid Penetrant Examination for ASME XI PSI/ISI," Revision 2
OPEP10-ZA-0018	"MT/ISI Dry Powder Magnetic Examination for ASME XI/FP," Revision 1
OPEP10-ZA-0024	"VT-1/3ASME XI Examination for VT-1and VT-3," Revision 1
UTI-PDI-UT-1	"CS/UT PDI Generic Procedure for the Ultrasonic Examination of Feritic Pipe Welds," Revision 0
UTI-PDI-UT-2	"SS/UT PDI Generic Procedure for the Ultrasonic Examination of Austenitic Pipe Welds," Revision 1
UTI-004	"0-DEG/UT Manual Ultrasonic Examination Using Logitudinal Wave Straight-Beam Technique," Revision 4

Examination Reports

MT-2003-061	UT-2003-012	UT-2003-016	PT-2003-020	UT-2003-008
UT-2003-007	UT-2003-014			

Condition Reports

01-12080	01-15628	02-3544	03-5358	01-13781
01-15555	02-1385			

Repair/Replacement Packages

01-01-094
01-02-021
01-02-022

Section 1EP5: Correction of Emergency Preparedness Weakness and Deficiencies

Procedures

0PGP03-ZX-0002 "Condition Reporting Process," Revision 25

Other Documents

Quality Audit Reports 2002-02 and 2003-04

Strategic Teaming and Resource Sharing (STARs) Assessment (CR 2002-6480)

Evaluation reports for drills conducted August 22, 2001; May 8, 2002; June 5, 2002; July 12, 2002; August 14, 2002; and August 21, 2002

Summaries of all corrective actions assigned to the emergency preparedness department between May 1, 2001, and May 1, 2003

CRs: 2001-8532, -8800, -9052, -10871, -11680, -14052, -14119, -18278, -19942; 2002 -986, -2323, -2324, -5195, -7529, -8502, -10345, -1928; and 2003-2501, -4510, and -4511

Section 4OA1: Performance Indicator Verification

Procedures

0PGP05-ZN-0007, "Preparation and Submittal of NRC Performance Indicators," Revision 1

0PGP05-ZV-0013, "Performance Indicator Tracking Guide," Revision 1

0ERP01-ZV-IN01, "Emergency Classification," Revision 5

0ERP01-ZV-IN07, "Offsite Protective Action Recommendations," Revision 8

Other Documents

Drill schedules for Calendar Years 2002 and 2003

Section 2OS1: Access Control to Radiologically Significant Areas

CRs: 02-14217, 02-16056, 02-16314, 02-16335, 02-16420, 02-16707, 02-17157, 02-17195, 02-17646, 02-18011, 02-18018, 02-18157, 02-18629, 03-880, 03-2359, 03-2576, and 03-3319

LIST OF ACRONYMS

ALARA	as low as reasonably achievable
ANSI	American National Standards Institute
CAP	corrective action program
CFR	*Code of Federal Regulations*
CR	condition report
DHR	decay heat removal
GL	generic letter
LER	licensee event report
LOCA	loss of coolant accident
MOV	motor-operated valve
NCV	noncited violation
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
PORV	power-operated relief valve
RCP	reactor coolant pump
RCS	reactor coolant system
RHR	residual heat removal
RWP	radiation work permit
SDP	significance determination process
URI	unresolved item
WAN	work authorization number