UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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ARLINGTON, TEXAS 76011-4005

April 18, 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 INSPECTION REPORT 50-498/02-06; 50-499/02-06

Dear Mr. Cottle:

On March 22, 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 March 27, 2003, with Mr. J. Sheppard and other members of your staff.

This 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 seven issues. Six were evaluated under the risk significance determination process (SDP) as having very low safety significance (Green). One is an unresolved item (URI) pending a risk significance evaluation. Four of these issues were violations which are being treated as noncited violations (NCV), 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.

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
50-498/02-06; 50-499/02-06

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-498 50-499
Licenses:	NPF-76 NPF-80
Report No:	50-498/02-06 50-499/02-06
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:	December 29, 2002, through March 22, 2003
Inspectors:	N. F. O'Keefe, Senior Resident Inspector G. L. Guerra, Resident Inspector J. M. Keeton, Project Engineer, Project Branch A G. A. Pick, Senior Physical Security Inspector, Plant Support Branch P. A. Goldberg, Senior Reactor Inspector, Engineering and Maintenance Branch D. P. Loveless, Senior Reactor Analyst
Approved By:	W. D. Johnson, Chief, Project Branch A, Division of Reactor Projects
Attachment 1:	Supplemental Information
Attachment 2:	TI 2515/149, Mitigating System Performance Indicator Verification

SUMMARY OF FINDINGS

South Texas Project Electric Generating Station, Units 1 and 2
NRC Inspection Report 50-498/02-06; 50-499/02-06

IR05000498-02-06; IR05000499-02-06; STP Nuclear Operating Company; 12/29/2002 - 03/22/2003; South Texas Project Electric Generating Station; Units 1 & 2. Integrated Resident and Regional Rpt; event followup, outage activities, PI&R, mitigating system perf ind pilot verif.

The inspection was conducted by resident inspectors and region-based engineering and plant support inspectors. Five Green noncited violations and two Green findings were identified. 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. Inspector Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A noncited violation with three examples was identified for three inadequate procedures required by Technical Specification 6.8.1.a and Regulatory Guide 1.33 that permitted maintaining hot standby plant conditions with the main steam lines isolated without establishing precautions to drain accumulated condensate. This contributed to an inadvertent safety injection actuation while initiating decay heat removal from an idle steam line. This violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-499/2002006-01). This issue was entered in the licensee's corrective action program under Condition Report 03-3694.

  This violation was more 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 through configuration control of the shutdown equipment alignment. This issue was determined to be of very low safety significance using Appendix G of the Significance Determination Process because it did not challenge defense-in-depth measures or equipment (Section 1R20.3).

- Green. A finding was identified relating to operator performance during the safety injection event. Operators became distracted and failed to control reactor coolant system pressure while operating the system in the manual mode, causing the lifting of a pressurizer power-operated relief valve. A human performance problem was identified for inattention to detail in monitoring primary plant pressure and understanding the operation of the master pressure controller, which led to challenging the reactor coolant system barrier integrity.

  This issue was more than minor because it affected the Initiating Events and Barrier Integrity Cornerstone objectives, which required a Phase 2 evaluation. The human performance issue was determined to have very low safety significance using a Phase 2 Significance Determination Process evaluation by assuming all mitigation equipment remained available, but the initiating event frequency for events which could be affected by a pressurizer power-operated relief valve opening increased by a factor of 10, in accordance with Manual Chapter 0609 guidance (Section 1R20.3).

- TBD. An apparent 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 in order to vent gases, evolved near the core, 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 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 MC 0609, and requires a risk analysis by NRC risk analysts. This will be treated as an unresolved item pending NRC assessment of the risk significance of this issue (Section 1R20.4) (URI 50-499/2002006-02).

- Green. A noncited violation of 10 CFR 50.65 was identified for not including the condensate polisher system within the scope of the Maintenance Rule Program as a system whose failure could cause a reactor trip. Unit 1 tripped on March 1, 2003, when a power supply that was original equipment failed. The power supply had no preventive maintenance item to periodically replace it, even though it controlled condensate flow through the condensate polishers and the condensate system function to automatically bypass the condensate polishers in the event of a high differential pressure condition. This violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-498/2002006-05). This issue was entered into the licensee's corrective action program under Condition Report 03-1837.

  This issue screened as Green using Phase 1 of the Significance Determination Process because it affected only one cornerstone and did not reduce the availability of mitigation equipment. This issue was more than minor because it affected the initiating events cornerstone objective to limit the likelihood of events that upset plant stability due to equipment reliability (Section 4OA3.2).

Cornerstone: Mitigating Systems

- Green. A noncited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified for failure to have adequate maintenance procedures for mechanism-operated cell switches in circuit breakers. A fault affecting one switchyard bus caused a partial loss of offsite power in each unit. The Unit 1 Train B standby diesel generator started but failed to automatically sequence loads as designed. Maintenance personnel identified that the operating mechanism for the cell switch was out of adjustment, preventing the switch from rotating fully and making full electrical contact that would cause the sequencer to initiate loading. The operating mechanism adjustment was not checked when the breaker was swapped a year earlier, and the misadjustment was sufficiently small that the switch functioned until this actual demand. The inspectors noted that the licensee did not have a maintenance procedure or preventive maintenance item to adjust, lubricate, clean, or fully test any of the mechanism-operated cell switches onsite. Failure to procedurally verify the proper adjustment and operation of the motor-operated cell switch following breaker replacement was a violation of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings.” This violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-498/2002006-03). This issue was entered into the licensee’s corrective action program under Condition Report 03-928.

The significance of this failure was minimal because operators were able to start loads manually. This issue was determined to be of very low safety significance using a Significance Determination Process Phase 1 screening. This issue was more than minor because it affected the mitigating systems cornerstone objective for ensuring the reliability of systems that respond to initiating events through maintenance procedure quality (Section 4OA3.1).

Cornerstone: Barrier Integrity

- Green. A noncited violation was identified for an inadequate procedure. A fault affecting one switchyard bus caused a partial loss of offsite power in each unit. Unit 2 lost power to both running reactor coolant pumps and, when operators attempted to restore them, a pressurizer power-operated relief valve lifted. Plant Operating Procedure 0POP02-RC-0004, “Operation of Reactor Coolant Pump,” Revision 19, was determined to be inadequate because it contained prerequisites for starting an initial reactor coolant pump which conflicted with (and caused operators to disregard) precautions to be aware of and limit pressure transients during reactor coolant pump starts. This was considered to be a violation of Technical Specification 6.8.1 and Regulatory Guide 1.33 for an inadequate procedure. Additionally, weaknesses were identified in operator understanding of the impact of their actions on the existing plant conditions and the operation of the pressurizer pressure control system. This violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-499/2002006-04). This issue was entered into the licensee’s corrective action program under Condition Report 03-949.

  This issue was more than minor because it affected objectives of the barrier integrity and initiating events cornerstones, which required a Phase 2 evaluation. This issue was determined to be of very low safety significance using a Significance Determination Process Phase 2 evaluation. The inspectors assumed that all mitigation equipment remained available, but the initiating events that could be affected by a pressurizer power-operated relief valve opening had the frequency of occurrence increased by a factor of 10, in accordance with Manual Chapter 0609 guidance (Section 4OA3.1).

- Green. A finding was identified for poor maintenance practices that caused main steam isolation valves to not fully close as designed. The inspectors determined that the maintenance personnel demonstrated a problem with maintenance effectiveness in that poor system cleanliness practices during maintenance contributed to two main steam isolation valves' inability to operate/isolate as designed. Even though the licensee engineers determined that the valve design limited the amount of possible steam leakage to within analyzed limits for accident analyses, this issue caused the plant to experience a cooldown cycle twice to effect repairs.

  This issue was considered more than minor because the human performance issue of poor maintenance performance in foreign material control while rebuilding main steam isolation valves affected the barrier integrity cornerstone. The safety significance of this issue was determined to be very low since the valves were capable of limiting steam flow within design requirements and since it screened as Green using a Phase 1 assessment of the Significance Determination Process. This issue is in the licensee's corrective action program under Condition Reports 02-19118, 02-19149, and 03-1325 (Section 1R12.1).

Report Details

Plant Status

Unit 1 began the inspection period at 100 percent power. Operators manually tripped Unit 1 on March1, 2003, in response to a loss of condensate flow through the condensate polisher portion of the system. The unit was restarted on March 3 and resumed full power operations shortly afterward. Unit 1 was in coastdown operations at the end of the inspection period.

Unit 2 began the inspection period in a forced outage for turbine generator repairs. The plant was started up on January 22, 2003. After 3 days, Unit 2 was shut down due to turbine generator torsional vibration problems for a forced outage. The unit was started up on March 12 and full power was reached on March 16. Unit 2 remained at full power at the end of the inspection period.

1. REACTOR SAFETY

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

1R04 Equipment Alignment (71111.04)

.1 Partial System Walkdown

a. Inspection Scope

Three partial system walkdowns were performed.

The inspectors performed a partial system walkdown of the Unit 1 Train B emergency safety features electrical system lineup after a Train B workweek on January 6, 2003. The inspectors walked down system equipment and control boards, using Plant Operating Procedure 0POP02-AE-0001, “AC Electrical Distribution Breaker Lineup,” Revision 12, and Plant Surveillance Procedure 0PSP03-EA-0002, “Channel III, 120VAC and 125 VDC Vital Bus Availability,” Revision 12, to verify that the trains were in a proper operational and standby lineups. The inspectors also examined component material condition of the system.

The inspectors performed a partial system walkdown of the Unit 2 essential cooling water system while it was in operation in support of maintaining Mode 5 conditions on February 11, 2003. The inspectors walked down system equipment and control boards using Plant Operating Procedure 0POP02-EW-0001, “Essential Cooling Water Operations,” Revision 27, to verify that the trains were in proper operational and standby lineups. The inspectors also examined component material condition of the system.

The inspectors performed a partial system walkdown of the Unit 1 Trains B and C essential chilled water while Train A was inoperable on February 18, 2003. The inspectors walked down system equipment and control boards using Plant Operating Procedure 0POP02-CH-0001, “Essential Chilled Water System,” Revision 30, to verify that the trains were in proper operational and standby lineups. The inspectors also examined component material condition of the system.

b. Findings

No findings of significance were identified.

.2 Semiannual System Walkdown

a. Inspection Scope

The inspectors performed a detailed system walkdown of the Unit 2 containment isolation system on February 5-14, 2003. The inspectors verified that all accessible penetrations of the containment were in a proper operational or standby alignment for the existing plant conditions. The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) for information on the required system conditions, alignment, and design criteria. The configuration information from UFSAR Figure 6.2.4-1 was verified during the walkdown. The inspectors verified that components were in good 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 Train B electrical switchgear and battery rooms on January 7, 2003 (Fire Zones Z042 and Z043)
- Unit 1 Standby Diesel Generator (SDG) 12 engine room on January 21, 2003 (Fire Zone Z501)
- Unit 1 Train C safety injection pump room on February 6, 2003 (Fire Zone Z305)
- Unit 2 component cooling water heat exchanger room on February 13, 2003 (Fire Zone Z142 and Fire Area 27)

- Unit 2 main control room on March 13, 2003 (Fire Zone Z034)
- Unit 1 essential cooling water pump rooms on March 18, 2003 (Fire Zones Z600, Z601, and Z602)

b. Findings

No findings of significance were identified.

1R07 Biennial Heat Sink Performance (71111.07B)

.1 Performance of Maintenance and Inspection Activities

a. Inspection Scope

During the week of March 10, 2003, the inspectors reviewed the licensee's cleaning and inspection methodology for the diesel generator jacket water and lube oil heat exchangers, the safety injection pump room coolers, and the electrical auxiliary building room coolers. In addition, the inspectors reviewed design and vendor-supplied information to ensure that the heat exchangers were performing within their design bases. The inspectors also reviewed the heat exchanger inspection results. Additionally, the inspectors verified that the licensee appropriately trended these inspection results, assessed the causes of the trends, and took necessary actions for any step changes in these trends. The inspectors reviewed the methods and results of heat exchanger inspection and cleaning and verified that the methods used to inspect and clean were consistent with industry standards and the as-found results were appropriately dispositioned such that the final conditions were acceptable.

b. Findings

No findings of significance were identified.

.2 Verification of Conditions and Operations Consistent with Design Bases

a. Inspection Scope

For the selected heat exchangers, the inspectors verified that the heat sink, heat exchanger condition and operation, and inspection and cleaning criteria were consistent with the design assumptions. Specifically, the inspectors reviewed the applicable calculations to ensure that the inspection and cleaning acceptance criteria for the heat exchangers were being applied consistently throughout the calculations. The inspectors also verified that the appropriate acceptance values for fouling and tube plugging for the diesel generator jacket water heat exchangers remained consistent with the values used in the design-basis calculations.

b. Findings

No findings of significance were identified.

.3 Identification and Resolution of Problems for Heat Exchanger Issues

a. Inspection Scope

The inspectors verified that the licensee had entered significant heat exchanger/heat sink performance problems into the corrective action 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 February 13, 2003. The inspectors observed two control room simulator scenarios that included a component cooling water leak at a reactor coolant pump (RCP), a fast load reduction, and a dropped control rod. The inspectors observed the performance of Crew 2B for clarity and formality of communications, correct use of procedures, performance of high risk operator actions, and the oversight and direction provided by the shift supervisor. The inspectors observed the operators' use of emergency action levels for proper emergency classification and reporting 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 Rule Implementation (71111.12)

.1 Routine Maintenance Effectiveness Reviews

a. Inspection Scope

The inspectors used the guidance provided in Inspection Procedure 71111.12 to independently assess maintenance effectiveness, including Maintenance Rule Program activities, work practices, and common cause failure issues. The following five equipment performance problems were reviewed:

- (Unit 1) SDG 12 cell switch failure during a partial loss of offsite power (Condition Report (CR) 03-928)

- (Unit 2) Main Steam Isolation Valves (MSIVs) 2B and 2C failures to fully close due to foreign material (CRs 02-19118, 02-19149, and 03-1325)

- (Unit 2) Reactor pressure vessel head vent valve failure (CR 03-1731)

- (Unit 2) Conoseal leaks on reactor vessel head penetrations (CRs 02-19264 and 03-1340)

- (Unit 1) Condensate polisher Power Supply PS-1 failure caused plant trip (CR 03-3192)

The inspectors verified that system, structure, and component (SSC) performance or condition problems were properly characterized in the scope of the Maintenance Rule Program. The inspectors assessed the adequacy of the expert panel's significance classification for the SSC. This included the appropriateness of the performance criteria established for the SSC (if applicable) and the adequacy of corrective actions for SSCs classified in accordance with 10 CFR 50.65 a(1) as applicable.

b. Findings

A Green finding was identified for poor maintenance practices associated with foreign material exclusion that caused two main steam isolation valves (MSIV) to not fully close as designed and requiring a plant cooldown cycle to repair.

On December 15, 2002, Unit 2 was manually tripped in response to a turbine blade failure. The operators attempted to isolate the turbine while maintaining the primary plant in hot standby, but found that MSIVs 2B and 2C would not completely shut off steam flow. Maintenance personnel subsequently identified two problems: (1) MSIV 2B had foreign material preventing the main valve from fully shutting; and (2) MSIV 2C had excessive wear near the antirotation device which allowed the pilot poppet to stop traveling before it fully shut. (The second issue is discussed in Section 4OA2 of this report. The operability of the valves is reviewed in Section 1R15.)

The foreign material found in MSIV 2B disintegrated while it was being removed. The foreign material was likely introduced into the valve or another part of the system during rebuilding of MSIV 2B or during steam generator (SG) replacement activities during the recently completed outage. Although condition reports were written for both issues affecting the valves, licensee personnel focused on the condition of MSIV 2C. For MSIV 2B, no corrective action was taken for the foreign material source and the cause was not identified. Both valves were repaired and returned to service.

Subsequently, on January 25, 2003, Unit 2 was shut down for additional turbine inspections and MSIV 2C was again found to allow steam to leak past the seat. It was identified that the stem and packing were scored by foreign material which could not be located. Licensee personnel concluded that the foreign material had originated inside the packing area, so it was probably left there during the previous maintenance work in December.

The inspectors determined that the two examples of MSIVs not shutting off steam flow represented a problem with maintenance effectiveness in that poor system cleanliness practices during maintenance contributed to these valves' inability to operate/isolate as designed. Even though licensee engineers determined that the valve design limited the amount of steam leakage that was possible to within analyzed limits for accident analyses, this issue caused the plant to experience a cooldown cycle twice to affect repairs.

This issue was considered more than minor because it represented a human performance issue of poor maintenance performance in foreign material control while rebuilding MSIVs and affected the barrier integrity cornerstone objectives. The safety significance of this issue was determined to be very low since it screened as Green using a Phase 1 assessment of the Significance Determination Process. This issue is in the licensee's corrective action program under Condition Reports 02-19118, 02-19149, and 03-1325.

.2 Periodic Evaluation Reviews (71111.12B)

a. Inspection Scope

During the week of January 27, 2003, the inspectors reviewed the South Texas Project Electric Generating Station reports documenting the performance of the last maintenance rule periodic effectiveness assessment. This periodic evaluation covered the period from July 2000 through August 2002.

The inspectors reviewed the program for the monitoring of risk-significant functions associated with SSCs using reliability and unavailability. The inspectors reviewed six SSCs/functions that had suffered degraded performance during the previous 2 years. Additionally, the performance of nonrisk-significant functions was monitored using plant level criteria.

The inspectors reviewed the conclusions reached by licensee personnel with regard to the balance of reliability and unavailability for specific maintenance rule functions. This review was conducted by examining the licensee engineers' evaluation of all risk significant functions that had exceeded performance criteria during the evaluation period.

The inspectors also examined South Texas Project Electric Generating Station personnel's evaluation of program activities associated with the placement of Maintenance Rule Program functions in Categories (a)(1) or (a)(2). Additionally, the inspectors reviewed the periodic evaluation conclusions reached by licensee personnel for the following systems: essential cooling water, main steam, emergency dc lighting, electrical auxiliary building ventilation, nuclear instrumentation, and 480 Vdc Class 1E load centers.

b. Findings

No findings of significance were identified.

.3 Identification and Resolution of Problems for Maintenance Effectiveness

a. Inspection Scope

The inspectors evaluated the use of the corrective action system within the Maintenance Rule Program for issues associated with risk significant systems. The review was accomplished by the examination of a sample of corrective action documents, maintenance work items, and other documents listed in the attachment. The purpose of the review was to establish that the corrective action program was entered at the appropriate threshold for the purpose of:

- Implementation of the corrective action process when a performance criterion was exceeded
- Correction of performance-related issues or conditions identified during the periodic evaluation
- Correction of generic issues or conditions identified during programmatic assessments, audits, or surveillances

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors assessed whether the performance of risk assessments for selected planned and emergent maintenance activities was in accordance with 10 CFR 50.65(a)(4) 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 five activities associated with:

- (Unit 1 and 2) North switchyard bus outage on January 28, 2003 (Condition Report Engineering Evaluation (CREE) 97-4343 and CR 03-925)

- (Unit 1) Reactor containment fan cooler leak repair on January 30, 2003 (Work Authorization Number (WAN) 244410)

- (Unit 1 and 2) Motor-operated valve (MOV) inspections on January 6 and 7, 2003 (CREE 03-1341-51)

- (Unit 2) Reactor pressure vessel head vent work on February 21, 2003 (WAN 245345)

- (Unit 2) Maintaining hot standby conditions with the main condenser unavailable due to turbine work on March 10, 2003

b. Findings

The maintenance risk assessment aspects of maintaining Unit 2 in hot standby with the main condenser unavailable are discussed in Section 1R20.3. No other findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions (71111.14)

.1 Fault in North Switchyard Bus Shunt Reactor Partial Loop for Both Units

The inspectors reviewed the human performance aspects of this event. The results of that review are documented in Section 4OA3.1.

.2 Loss of Water Inventory in Unit 2 Reactor Pressure Vessel Due to Gassing

The inspectors reviewed the human performance aspects of this event. The results of that review are documented in Section 1R20.4.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed seven operability evaluations conducted by licensee personnel during the report period involving risk-significant systems or components. The inspectors used Inspection Procedure 71111.15 and Generic Letter 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 2) Review of MSIV 2C failure to fully seat on December 16, 2003 (CREE 02-19118-9)
- (Unit 2) Review of MSIV 2B failure to fully seat on December 16, 2002 (CREE 02-19149-1)
- (Unit 2) Review of MSIV 2C failure to fully seat on January 25, 2003 (CREE 03-1325-1)
- (Unit 1) Component cooling water and reactor containment building chilled water intersystem leakage on January 27, 2003 (CR 02-19053)
- (Unit 2) SG power-operated relief valve (PORV) operability affected by water built up in adjacent main steam lines on March 18, 2003 (CR 03-3694)
- (Unit 1) Reactor Containment Fan Cooler 12A heat capacity following isolation of one coil due to leakage on February 12, 2003 (CREE 03-1117-06)
- (Unit 1 and 2) MOV inspection results during February and March 2003 (CREE 03-1341)

In regard to the operability of MSIVs due to leakage, the inspectors reviewed the licensee engineers' operability evaluation and discussed it with the licensee's engineering, licensing, and accident analysis personnel. The inspectors discussed concerns that the concurrent failures of MSIVs 2B and 2C were not evaluated together with engineering personnel and reviewed the subsequent revised evaluation.

For the MOV actuator issue, the inspectors reviewed the technical evaluations performed during this inspection period for the 252 actuators inspected in response to the failure of residual heat removal (RHR) Train 2C Suction Valve RH-MOV-0060C. These evaluations were discussed with the licensee's MOV engineer and NRC MOV specialists. Additional inspection results will be reviewed in the next integrated inspection report.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

During the week of February 10, 2003, the inspectors reviewed licensee-identified operator workarounds and other existing equipment conditions with the potential to be workarounds to verify that they had been identified and assessed in accordance with STP's Total Impact Assessment document and to determine if the functional capability of the system or human reliability in responding to initiating events had been affected.

The ability of operators to implement normal and emergency operating procedures with the existing equipment issues was specifically evaluated.

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 six maintenance activities:

- (Unit 2) Safety Injection Loop 2A Cold Leg Injection Valve SI-MOV-314 packing replacement on January 28, 2003 (WAN 244121)
- (Unit 2) Plant Surveillance Procedure 0PSP03-AF-0007, "Auxiliary Feedwater Pump 24 Inservice Test," Revision 23, following maintenance on January 2, 2003 (WAN 219683)
- (Unit 1) SDG 12 cell switch troubleshooting for a failure on January 21, 2003 (CREE 02-928, WAN 244130)
- (Unit 2) Plant Surveillance Procedure 0PSP03-RH-0007, "Residual Heat Removal System Valve Operability Test," Revision 13, for RH-MOV-60C actuator repair on January 31, 2003 (WAN 244536)
- (Unit 1) Replacement of actuator on RHR Heat Exchanger 1A Outlet Valve RH-FV-3860 on March 21, 2003 (WAN 228281)
- (Unit 2) Plant Surveillance Procedure 0PSP03-MS-0002, "Main Steam System Cold Shutdown Valve Operability Test," Revision 10, for MSIV 2C on February 21, 2003 (WAN 223820)

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 UFSAR, 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 Outage Activities (71111.20)

.1 Review of the Unit 1 Refueling Outage Plan

a. Inspection Scope

On March 19, 2003, the inspectors reviewed the Unit 1 Eleventh Refueling Outage Shutdown Risk Assessment and the outage schedule to verify that the licensee's outage management appropriately considered risk in planning and scheduling the outage activities. The results of the licensee's Outage Risk Assessment and Management Program, time-to-boil, and time-to-core damage profiles were reviewed against the schedule of activities to identify periods of increased risk and activities for additional inspection focus. The work schedule and risk profiles were discussed with the operations support outage coordinator. The inspectors observed new fuel receipt inspections on February 20, 2003.

The inspectors focused on the following activities:

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

b. Findings

No findings of significance were identified.

.2 Unit 2 Forced Outage Activities

a. Inspection Scope

Unit 2 was in a forced outage from December 15, 2002, through January 22, 2003, and from January 24 through March 16. 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, decay heat removal, inventory control, reactivity control, and containment integrity. The inspectors observed operator performance during the reactor shutdown evolutions on December 15, 2002, and January 24, 2003, and the reactor startup on March 12, 2003.

b. Findings

No findings of significance were identified.

.3 Inadvertent Safety Injection Actuation While Shutdown

a. Inspection Scope (71111.20 and 71153)

The inspectors conducted an inspection into the chain of events that led to an inadvertent safety injection actuation on March 9, 2003. The inspectors reviewed plant computer data for the period surrounding the event to assess plant conditions. Control room logs were reviewed and the plant and operators' responses were discussed with the operating crew. The licensee's root cause investigation results and risk assessment were discussed with members of the Event Review Team and operations management to assess the adequacy of the assessment and corrective actions. The inspectors reviewed CRs 03-3694, 03-3697, and 03-3703.

b. Findings

A Green noncited violation (NCV) was identified for an inadequate procedure that permitted maintaining hot standby plant conditions with the main steam lines isolated without establishing precautions to drain accumulated condensate. This contributed to an inadvertent safety injection actuation while initiating decay heat removal from an idle steam line. A Green human performance finding was also identified because operators failed to control reactor coolant system (RCS) pressure, causing the lifting of a pressurizer PORV. This event affected Initiating Events and Barrier Integrity Cornerstone objectives.

Safety Injection Actuation Event

Unit 2 was in a forced outage for turbine repairs. To isolate the turbine and main condenser work area, the MSIVs and drain valves were tagged shut. The primary plant was maintained in hot standby by running RCPs to add heat and removing excess heat from one steam generator at a time through the SG PORV. The operators did not recognize that the idle main steam lines accumulated significant quantities of condensate. On March 9, 2003, operators shut SG PORV 2C and opened SG PORV 2B. A significant amount of water was observed to "percolate" from the SG PORV 2B vent pipe, causing steam line pressure and steam flow indications to oscillate. A safety injection actuation occurred on low steam line pressure, starting all appropriate safety equipment and initiating a Phase A containment isolation. The primary system was at normal operating pressure, so the safety injection system did not discharge into the primary plant.

The inspectors concluded that the operators did not adequately assess the impact of operating in hot standby with the steam lines and drains isolated and the condenser not available. As a result, no alternate method of draining condensate accumulated in the steam lines was implemented. The inspectors determined that, at a minimum, the operators used the following Plant Operating Procedures to maintain similar plant conditions :

0POP03-ZG-0001, “Plant Heatup,” Revision 35
0POP03-ZG-0007, “Plant Shutdown from 100% to Hot Standby,” Revision 22
0POP03-ZG-0007, “Plant Cooldown,” Revision 36

Each of these procedures permitted maintaining primary plant heat removal by manually controlling SG PORVs with the steam lines isolated, and none contained a precaution regarding the need to periodically drain condensate from isolated steam lines. Each of these are procedures required by Technical Specification 6.8.1 and Regulatory Guide 1.33. These procedures were determined to be inadequate because they permitted operation in a plant condition which led to an inadvertent safety injection actuation because adequate precautions were not specified, which was a violation. This violation was more 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 through configuration control of the shutdown equipment alignment. This issue was determined to be of very low safety significance using Appendix G of the Significance Determination Process. Therefore, this violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-499/2002006-01). This issue was entered into the licensee’s corrective action program under CR 03-3694.

Prior Opportunity To Identify the Problem

The licensee’s Event Review Team identified that a similar, but less severe, event occurred 2 months earlier under similar plant conditions. On January 20, 2003, erratic steam pressure control was experienced while swapping heat removal from SG PORV 2A to 2B. Troubleshooting of the operation of SG PORV 2B identified no equipment problems, so CR 03-963 was closed. Licensee personnel defined the problem to be addressed very narrowly as apparent improper operation of the SG PORV and did not attempt to further identify the cause or review the impact of the existing plant conditions. Licensee personnel missed an opportunity to identify the problem and correct it before it became a more significant event because they did not consider the potential for a more significant event in classifying the earlier CR. Instead, it was classified as a Condition Adverse to Quality - Department Level, which did not require a determination of the cause.

Operator Performance Caused PORV Lift

At the time of the event, pressurizer backup heaters were energized in manual. This was commonly done by the operators to raise pressure enough to cause the pressurizer spray valves to open, mixing the pressurizer with the RCS. However, the Phase A containment isolation stopped the air supply to the pressurizer spray valves, causing them to fail shut. Operators did not secure the backup heaters after the safety injection occurred.

The RCS pressure boundary was challenged by the PORV lifting 18 minutes after the safety injection actuation because operators became distracted and failed to control RCS pressure while it was in manual control. Operators failed to recognize that the pressurizer pressure controller integral feature would cause the PORV to open at a pressure lower than the nominal pressure setpoint, because the setpoint error (caused by backup heaters raising pressure) would have an additional error signal applied as time passed with the error still present. In this case, the PORV opened with a pressure of 2270 psig, well below the nominal setpoint of 2335 psig. Operators responded appropriately and restored normal pressurizer operation. The PORV lift could have been avoided by securing the backup heaters, effectively restoring automatic system operation.

This human performance issue was determined to have very low safety significance using a Phase 2 Significance Determination Process evaluation. The inspectors assumed that all mitigation equipment remained available, but the initiating events that could challenge a pressurizer PORV had the frequency of occurrence increased by a factor of 10, in accordance with Manual Chapter 0609 guidance. This issue was more than minor because it affected the barrier integrity cornerstone objective of providing reasonable assurance that physical barriers of the RCS protect the public from radionuclide release caused by operator performance.

.4 Reactor Head Voiding/Inadvertent Loss of Water Inventory:

a. Inspection Scope (71111.20 and 71153)

The inspectors conducted an inspection into the chain of events that led to an inadvertent loss of water inventory in the reactor head on February 21, 2003. The inspectors reviewed plant computer data for the period surrounding the event to assess plant conditions. Control room logs were reviewed and the plant and operators' responses were discussed with the operating crew. The Event Review Team's root cause investigation results and risk assessment were discussed with members of the Event Review Team and operations management to assess the adequacy of the assessment and corrective actions. The inspectors reviewed CR 03-2751. Logs and plant computer data were also reviewed for the period of December 20-25, 2002, when similar plant conditions existed. The licensee's response to similar prior industry events was reviewed (CRs 98-1540, 97-19952, 97-11843, 96-15748, 96-8448, 94-467, and 94-427).

b. Findings

An apparent 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 before it was recognized.

On February 20, 2003, operators drained water in the RCS in Unit 2 to a level of 45 feet. This was a few inches below the Number 1 heated-junction reactor vessel water level probe and about 5.5 feet above the Number 2 probe. These probes had the ability to indicate either "dry" or "wet." Level was being maintained using the magnetic sight glass. 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 45 feet. However, when the operators noted that the Number 2 probe indicated “dry,” they realized that gas had accumulated, causing the sight glass to indicate falsely high.

Plant Operating Procedure 0POP03-ZG-0007, “Plant Cooldown,” Revision 34, 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. Prior to draining to this point, operators had been aware of, and had been following, Precaution 4.27, which stated “In Mode 5 with RCS depressurized and maintaining RCS inventory at a fixed value, periodic venting of the reactor vessel head may be required due to gas buildup.” Venting was being performed every 6-8 hours when level was at 50 percent in the pressurizer.

The intended work to replace the head vent valve was originally planned and scheduled as electrical work external to the valve. The work scope was changed when the problem was determined to be in the valve internals, which required draining down to permit a breach of the RCS boundary. The senior licensed operators that approved the tagout realized that securing the vent path would result in accumulating nitrogen, but each underestimated the increased rate of gas evolution with a lower pressure (at the lower water level) and the duration of the work. The work was estimated to take 36 hours, but the senior reactor operators thought it would take 12-24 hours. Instead of accumulating enough to displace 300-600 gallons in 12-24 hours, as the operators estimated, 4000 gallons were displaced in 20 hours.

The organization 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. The impact of this change was not appreciated when the work was scheduled. Additionally, the duration of the work was not clearly communicated to the operators who were responsible for approving the work.

The licensee’s program for assessing shutdown risk permitted the option to not implement the Shutdown Risk Assessment Group (SRAG) process for forced outages. This outage was entered as a forced outage for work that did not involve the reactor plant or other safety-related equipment, so the SRAG was not initially implemented. Also, this decision was not revisited when work scope additions were made to include replacing the reactor head vent valve and four conoseals in the reactor head, which required cold shutdown and unusual plant conditions. Further, these work items did not affect the results of the Outage Risk Assessment Monitoring program, which was also cited by licensee personnel as a reason for not implementing the SRAG. However, the inspectors determined that Outage Risk Assessment Monitoring program’s simplified modeling did not address the incremental risk associated with operating at different water inventory levels or with the potential for unreliable instrumentation. A more thorough review of the planned evolution by the experienced members of the SRAG might have better recognized the impact of shutting the reactor head vents.

The inspectors reviewed the licensee's response to previous nuclear industry experience with similar events. Licensee personnel reviewed each and concluded that the existing procedures and training were adequate; however, the inspectors concluded that these reviews were narrowly focused and did not adequately consider prolonged operation in Mode 5. The latter was the condition of concern in the industry events documents and was the case in this event.

This was considered to be a failure to follow procedures required by Technical Specification 6.8.1 and Regulatory Guide 1.33 since the precautions included appropriate information to be able to avoid this problem. The plant conditions were being maintained within Operating Procedure 0POP03-ZG-0007, "Plant Cooldown," Revision 36, which required the reactor head to be vented, but operators closed the vent path for maintenance without fully evaluating the potential safety impact of taking that equipment out of service. This issue is in the licensee's corrective action program under CRs 03-2751 and 03-3443. 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 and requires a risk analysis by NRC risk analysts. This will be treated as an unresolved item pending NRC assessment of the risk significance of this issue (URI 50-499/2002006-02).

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; 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 tests:

- (Unit 2) 0PSP03-CV-0014, "Chemical Volume Control System Equipment Verification," Revision 4, on January 30, 2003

- (Unit 1) 0PSP03-EW-0018, "Essential Cooling Water System Train B Testing," Revision 27, on January 31, 2003

- (Unit 2) 2TEP07-TM-0003, "Turbine Generator Testing," Revision 0, on March 13, 2003

- (Unit 2) 0PEP05-HE-0002, "Control Room Envelope Ventilation Operational Test," Revision 0, on February 21, 2003

- (Unit 2) 0PSP02-RC-0455, "Pressurizer Pressure Analog Channel Operability

Test," Revision 16, on March 20, 2003

- (Unit 1) 0PSP02-RC-0455, "Pressurizer Pressure Analog Channel Operability Test," Revision 15, on March 12, 2003

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed three temporary modifications, 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.

- T2-03-122-1, "Temporary Drain Line for Auxiliary Feedwater Pump 24," on January 6, 2003

- T1-03-1117-5, "Reactor Containment Fan Cooler Leak Repair," on February 10, 2003

- T2-03-2102-1, "Main Turbine Generator Modifications for Testing," on March 13, 2003

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA2 Identification and Resolution of Problems (71152)

.1 MSIV Leakage Issues

a. Inspection Scope

The inspectors used Inspection Procedure 71152 to review the licensee's problem identification and resolution regarding the failure of MSIV 2C to fully close due to wear in the antirotation device on December 15, 2002. Licensee personnel identified the apparent cause to be that MSIV 2C had excessive wear near the antirotation device which allowed the pilot poppet to stop traveling before it fully shut. The inspectors assessed the adequacy of the actions listed in a previous CR (CR 02-12139) to address industry failures of this type and other operating experience with these Atwood-Morrill MSIVs. The inspectors reviewed the change to the planned actions based on the failure onsite, documented in CR 02-19118. The review of the operability evaluation is documented in Section 1R15 above.

b. Findings

No findings of significance were identified.

4OA3 Event Followup (71153)

.1 Fault in North Switchyard Bus Shunt Reactor, Partial Loss of Offsite Power in Both Units

a. Inspection Scope

The inspectors responded to the site on January 19, 2003, to assess operator response to the event and plant conditions. The inspectors interviewed control room operators in both units, assessed plant response through direct observation and by reviewing plant recorder data, and reviewed operating logs. The inspectors discussed the results of the joint owner/licensee inspection of the switchyard components with the cognizant design engineer. Pressurizer PORV response was discussed with system engineering personnel. The root cause assessment process and results were discussed with members of both Event Review Teams. The inspectors reviewed the failure history associated with mechanism-operated cell switches, and the licensee's evaluation of recent industry operating experience with these types of switches. CRs 03-925, 03-928, and 03-949 were reviewed, along with the following procedures:

- 0POP04-AE-0001, "First Response To Loss Of Any Or All 13.8 KV or 4.16 Bus," Revision 26
- 0POP04-AE-0002, "Loss Of One Or More 13.8 KV Auxiliary Or The Non-Class 4.16 KV Bus D," Revision 1
- 0POP04-AE-0003, "Loss Of Power To One Or More 13.8 KV Standby Bus," Revision 5
- 0POP04-RC-0002, "Reactor Coolant Pump Off Normal," Revision 19

b. Findings

A fault affecting one switchyard bus caused a partial loss of offsite power in each unit. Two Green NCVs were identified for inadequate procedures. The Unit 1 Train B SDG started but failed to load automatically because of improper maintenance to the associated mechanism-operated cell switch. Unit 2 lost power to both running RCPs and, when operators attempted to restore them, they caused a pressurizer PORV to lift.

Summary of Event

On January 19, 2003, the north switchyard bus automatically deenergized in response to a fault. A shunt reactor was being placed in service by offsite transmission and distribution personnel when the isolation occurred. The isolation of this bus deenergized the Standby 1 transformer. At the time, this transformer was supplying power to Trains B and C safety buses in Unit 1 and to balance-of-plant equipment and Train A safety buses in Unit 2.

Unit 1 Train B Failed to Sequence Loads

In Unit 1, the SDGs for Trains B and C started, but the Train B load sequencer did not start any loads; operators were able to start the loads manually. Electricians subsequently identified that the connecting rod between the mechanism-operated cell switch and the SDG output breaker was out of adjustment, preventing the cell switch from fully rotating and making complete electrical contact. This prevented the load sequencer from recognizing that the breaker was shut and initiating the sequenced starting of safety equipment as designed. The licensee concluded that the linkage had not been adjusted in February 2002, when the SDG-12 output breaker had been replaced. Minor tolerance differences between breakers could impact the operation of the cell switch operating mechanism. The licensee was able to demonstrate that the cell switch for SDG-12 had functioned properly during every demand since breaker replacement except this one. The licensee concluded that the low voltage signal (24 Vdc) and the lack of proper contact wiping, caused by the partial contact of conductors, combined to degrade the electrical continuity until the failure occurred.

The inspectors noted that the licensee's postmaintenance testing to ensure proper cell switch operation checked the higher voltage contact continuity, but did not check the low voltage contacts associated with the load sequencer. Further, the licensee performed no preventive maintenance that checked the lubrication, cleanliness, adjustment, or required force to operate the cell switch operating mechanism. Similar mechanism-operated cell switches were used in other safety-related breaker applications.

Failure to procedurally verify the proper adjustment and operation of the mechanism-operated cell switch following breaker replacement was a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." This issue was determined to be of very low safety significance using a Phase 1 screening using the Significance Determination Process. Therefore, this violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-498/2002006-03). This issues was entered into the licensee's corrective action program under CR 03-928. This issue was more than minor because it affected the mitigating systems cornerstone objective for ensuring the reliability of systems that respond to initiating events through maintenance procedure quality.

Unit 2 Pressurizer PORV Lifted

At the time of the event, Unit 2 was in an abnormal electrical bus lineup because troubleshooting was in progress on the main generator breaker. The Standby 1 transformer was supplying power to Unit 2 balance-of-plant equipment and Train A safety buses. Unit 2 had been maintaining hot standby conditions by running two RCPs. When the north bus isolated, power was lost to both RCPs. Operators spent several hours correcting an RCP seal high temperature condition, then started RCP 2A. Operators did not recognize it, but the low core decay heat and lack of RCPs running allowed RCS temperature to drop 16°F below the temperature of the secondary side of the SGs. When the RCP was started, heat was transferred from the secondary side to the primary side, causing a pressurizer insurge and a pressure increase. Both pressurizer spray valves received a full-open demand, but spray flow was minimal since only Spray Line A had flow and half of this flow was diverted backwards through Spray Line D. The existing master pressure controller error was added to the integral feature and the insurge-induced pressure increase, causing the pressurizer PORV to lift at 2322 psig, a little below the nominal setpoint of 2335 psig.

Plant Operating Procedure 0POP02-RC-0004, “Operation of Reactor Coolant Pump,” Revision 19, contained prerequisites for starting an initial RCP which conflicted with (and caused operators to disregard) precautions and limit pressure transients during RCP starts. This was considered to be a violation of Technical Specification 6.8.1 and Regulatory Guide 1.33 for an inadequate procedure. This issue was determined to be of very low safety significance using a Significance Determination Process Phase 2 evaluation. The inspectors assumed that all mitigation equipment remained available, but the initiating events that could challenge a pressurizer PORV had the frequency of occurrence increased by a factor of 10, in accordance with Manual Chapter 0609 guidance. Therefore, this violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-499/2002006-04). This issues was entered into the licensee’s corrective action program under CR 03-949. This issue was more than minor because it affected the barrier integrity cornerstone objective of providing reasonable assurance that physical barriers of the RCS protect the public from radioactive nuclide release through human performance in operations and the initiating events cornerstone objective of limiting the likelihood of events that challenge critical safety functions by having reliable equipment performance to maintain barrier integrity against a loss of reactor coolant.

.2 Unit 1 Trip on Loss of Condensate Flow

a. Inspection Scope

The inspectors responded to the site on March 1, 2003, to assess operator response to the event and plant conditions. The inspectors interviewed control room operators in both units, assessed plant response through direct observation and by review, reviewed plant recorder data, and reviewed of operating logs. The root cause assessment process and results were discussed with members of both Event Review Teams.
CR 03-3192 was reviewed, along with the following procedures:

- 0POP05-E0-E000, “Reactor Trip of Safety Injection,” Revision 16
- 0POP05-E0-ES01, “Reactor Trip Response,” Revision 20

b. Findings

A Green NCV was identified for not including the condensate polisher system within the scope of the Maintenance Rule Program as a system whose failure could cause a reactor trip. Unit 1 tripped when a power supply that was original equipment failed; the power supply had no preventive maintenance item to periodically replace it, even though it controlled condensate flow through the condensate polishers and the automatic bypass function.

Unit 1 tripped from 100 percent power on March 1, 2003, when condensate polisher Power Supply PS-1 failed. This caused a loss of condensate flow when all condensate polisher outlet valves shut, and the condensate polisher bypass valve did not sense the high differential pressure condition and open. Operators realized that condensate flow could not be reestablished promptly, and manually tripped the unit. The power supply that failed was original equipment with about 15 years of service time. This power supply had no preventive maintenance associated with it and had not been identified as a single failure that could cause a trip. Its failure removed some indications which made it more difficult to diagnose and address before a plant trip was necessary.

A few age-related failures of similar power supplies in the same system had occurred in the past without experiencing plant trips. The power supplies were simply replaced without creating a preventive maintenance item to replace them periodically. Licensee personnel had not assessed whether those problems applied to other power supplies in the same system and had thus failed to recognize the trip potential. As a result, corrective actions were narrow and no preventive maintenance item was created to periodically replace the power supplies in this system.

The inspectors noted that licensee personnel had not included the condensate polisher system in the scope of the Maintenance Rule Program, in part because they had incorrectly concluded that a failure of the system could not cause a plant trip. Failure to include the condensate polisher system in the scope of the Maintenance Rule Program was a violation of 10 CFR 50.65(b)(2)(iii). This issue was determined to be of very low safety significance using a Phase 1 screening under the Significance Determination Process. Therefore, this violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-498/2002006-05). This issue was entered into the licensee’s corrective action program under CRs 03-3192 and 03-1837. This issue was more than minor because it affected the initiating events cornerstone objective to limit the likelihood of events that upset plant stability due to equipment reliability.

4OA5 Other Activities

.1 Temporary Instruction 2515/149: Mitigating System Performance Indicator (MSPI) Pilot Verification

a. Inspection Scope

The inspectors reviewed the licensee's treatment of the following systems covered by this pilot:

Standby Diesel Generators
Essential Cooling Water System
Component Cooling Water System

The inspectors reviewed system drawings, spreadsheets, design basis documents, Graded Quality Assurance system assessment notebooks, and equipment history. The inspectors also reviewed the licensee's MSPI Basis Document, which provided a description of the boundaries and active components.

The inspectors confirmed that the licensee correctly identified risk significant functions for trains within these systems. The licensee selected the risk significant functions using the Graded Quality Assurance risk ranking process in accordance with their risk-informed exemption to special treatment requirements. All functions determined to have "high" or "medium" risk significance were included. Each of the above functions had an appropriate success criteria at the train level (none of the reviewed systems had a separable segment below the train level) which were consistent with the licensee's probabilistic risk assessment (PRA) analysis, Technical Specifications, and design basis documentation.

The inspectors confirmed that the licensee's definition of the system/train boundaries and the identification of active components was in accordance with the Nuclear Energy Institute (NEI) guidance, with one exception: the NEI guidance specified that diesels should include the starting air receivers, whereas the licensee specified that only one was required. The licensee planned to change this to conform to the guidance. The inspectors also confirmed that the active components were accounted for in the site-specific NEI spreadsheet and that the spreadsheet used industry reliability values in accordance with the guidance, with one exception: the licensee used the higher unreliability values from Table 2 under high pressure safety injection for their RHR function. This was done because these values more closely approximated the site's reliability history. The inspectors noted that this would have the effect of establishing a baseline which was higher than actual and industry averages, so a more unreliable performance would be permitted. The licensee agreed that using a different value than explicitly intended in the guidance should be done only after getting approval; the licensee intended to submit a Frequently Asked Question on this topic.

The inspectors reviewed the site-specific NEI spreadsheet and determined that most historical data was properly entered. However, the quality of the licensee's data reviews was questionable since the inspectors noted a number of data entry errors. In particular, this included some entries which were double the actual value and some entries which were correct but the original data source had to be corrected. The inspectors also identified that the licensee had reported site-specific unavailability data which included both planned and unplanned time, contrary to the guidance. The guidance specified that site-specific planned unavailability and generic industry unplanned unavailability was to be used. The licensee did this because the process of separating the data into the two categories was too time consuming to meet the initial reporting deadline, but expected that the data reported would conservatively overestimate unavailability. The inspectors noted that this would have the effect of establishing a baseline which was higher than actual, which allows a nonconservative bias in future unavailability. During the inspection the licensee removed the unplanned unavailability time and planned to revise the data when the November data was submitted.

The inspectors noted that the licensee had tentatively concluded that they had a number of invalid indicators, according to the definitions in the guidance.

Sections 03.11.a and 03.11.c were not completed as written because the staff did not qualify the licensee's updated PRA for use prior to or during the MSPI pilot. However, the activities conducted and the results obtained for these sections are documented in an attachment to this inspection report. During this review, the licensee identified two modeling errors that resulted in incorrect reporting of the MSPI. These errors were corrected and have been documented in Attachment 2 to this inspection report.

b. Findings

The licensee made a reasonable best effort to provide accurate and complete data for this voluntary pilot program. Errors identified during the audit were corrected. The specific audit results of Temporary Instruction 2515/149 are documented in Attachment 2 to this report.

.2 Review of Periodic Site Evaluation by the Institute of Nuclear Power Operations

a. Inspection Scope

The resident inspectors reviewed the results of the periodic evaluation of site activities performed by the Institute of Nuclear Power Operation in April and May 2002.

b. Findings

No findings of significance were identified.

.3 (Closed) Unresolved Item 50-498;499/0015-01: Potentially ineffective protective strategy demonstrated during table top drills. The inspectors determined during inspection of the Interim Compensatory Measures in accordance with Temporary Instruction 2515/148 that the licensee had changed their protective strategy since this item was originally identified. These changes negated the concerns expressed because of the scope of changes and the type of strategy being implemented. Specifically, the licensee installed hardened defensive positions, strategically placed barriers, and changed the weapons being used in the defensive strategy.

4OA6 Meetings, including Exit

Exit Meeting Summary

The results of the maintenance rule implementation inspection were presented to Mr. G. Parkey, Vice President, Generation, and other members of licensee management at the conclusion of the inspection on January 30, 2003.

The results of the heat sink performance inspection were presented to Mr. G. Parkey and other members of licensee management on March 13, 2003.

The results of the resident inspection were presented to Mr. J. Sheppard, Vice President and Assistant to the President/CEO, and other members of licensee management at the conclusion of the inspection on March 27, 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.

ATTACHMENT 1

Supplemental Information

PARTIAL LIST OF PERSONS CONTACTED

Licensee:

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, Plant General Manager
S. Head, Manager, Licensing
T. Jordan, Vice President, Engineering and Technical Services
W. Jump, Manager, Training
A. Kent, Manager, Testing/Programs
D. Leazar, Manager, Fuels and Analysis
M. McBurnett, Manager, Quality and Licensing
F. Mallan, Director, Business Services
M. Meier, Manager, Generation Station Support
M. Murray, Supervisor, System Engineering
G. Parkey, Vice President, Generation
K. Richards, Director, Outage
D. Rencurrel, Manager, Operations
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, Maintenance Rule Coordinator

NRC:

T. Scarbrough, Mechanical Engineering Branch, NRR

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-499/2002006-01	NCV	Violation of Technical Specification 6.8.1 and Regulatory Guide 1.33 for inadequate procedure for ensuring steam lines are periodically drained (Section 1R20.3)
50-499/2002006-02	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 1R20.4)
50-498/2002006-03	NCV	Criterion V violation for inadequate maintenance procedure due to failure to procedurally verify the proper adjustment and operation of the motor-operated cell switch following breaker replacement. (Section 4OA3.1)
50-499/2002006-04	NCV	Violation of Technical Specification 6.8.1 and Regulatory Guide 1.33 for inadequate procedure for starting first RCP (Section 4OA3.1)
50-498/2002006-05	NCV	Violation of Technical Specification 10 CFR 50.65 for not including the condensate polisher system in the Maintenance Rule Program (Section 4OA3.2)

<u>Closed</u>

50-499/2002006-01	NCV	Violation of Technical Specification 6.8.1 and Regulatory Guide 1.33 for inadequate procedure for ensuring steam lines are periodically drained (Section 1R20.3)
50-498/2002006-03	NCV	Criterion V violation for inadequate maintenance procedure due to failure to procedurally verify the proper adjustment and operation of the motor-operated cell switch following breaker replacement (Section 4OA3.4)
50-499/2002006-04	NCV	Violation of Technical Specification 6.8.1 and Regulatory Guide 1.33 for inadequate procedure for starting first RCP (Section 4OA3.4)
50-498/2002006-05	NCV	Violation of Technical Specification 10 CFR 50.65 for not including the condensate polisher system in the Maintenance Rule Program (Section 4OA3.2)
50-498;499/2000015-01	URI	Potentially ineffective protective strategy demonstrated during table top drills (Section 4OA5.3)

LIST OF ACRONYMS USED

CR	condition report
CREE	condition report engineering evaluation
MOV	motor-operated valve
MSIV	main steam isolation valve
MSPI	mitigating system performance indicator
NCV	noncited violation
NEI	Nuclear Energy Institute
PORV	power-operated relief valve
RCP	reactor coolant pump
RCS	reactor coolant system
SDG	standby diesel generator
SG	steam generator
SRAG	Shutdown Risk Assessment Group
SSCs	structures, systems, or components
UFSAR	Updated Final Safety Analysis Report
URI	unresolved item
WAN	Work Authorization Number

DOCUMENTS REVIEWED

Condition Reports

97-14662	01-4969	01-15552	02-5545	02-13520
97-18192	01-6101	01-16179	02-5743	02-13856
99-2925	01-8419	01-16313	02-7943	02-13860
00-8005	01-11163	02-1839	02-8136	02-15252
00-13689	01-13234	02-4132	02-8604	03-3895
01-3664	01-14883	02-4199	02-8676	

Preventive Maintenance

90001607

Procedures

0PCP01-ZA-0038, “Plant Chemistry Specification,” Revision 23

0PEP07-EW-0001, “Performance Test for Essential Cooling Water Heat Exchangers,” Revision 6

0PGP04-ZA-0002, “Engineering Evaluation for CR# 01-11409-2,” Revision 3

0PGP04-ZA-0002, “Engineering Evaluation for CR# 02-285-02”

0PGP04-ZE-0313, “Maintenance Rule Program,” Revision 4

0PMP04-ZG-0004, “Bench Testing of Relief and Safety Relief Valves,” Revision 16

0PMP04-ZG-0011, “Heat Exchanger Cleaning (General Guidelines and Instructions,” Revision 5

0PS04-DG-0002, “Standby Diesel Generator 5 Year Inspection,” Revision 9

Maintenance Rule Basis Document Guideline, Revision 7

Miscellaneous

Report FR-071125, “Solenoid Valve,” September 5, 2001

Audit 02-05, “Comprehensive Risk Management, Exemptions from Special Treatment Requirements of 10CFR parts 21, 50, and 100,” July 25, 2002

Systems Changed from A1 to A2 in Last Two Assessment Periods, July 31, 2000, to July 31, 2001, and July 31, 2001, to August 22, 2002

System Health Rating, Essential Cooling Water Screen Wash, April 24, 2002

System Health Rating, HVAC Electrical Auxiliary Building, June 4, 2002

System Health Rating, Emergency DC Lighting, December 19, 2002

System Health Report, Main Steam, January 30, 2002

System Health Report, Nuclear Instrumentation, December 3, 2001

System Health Report, 480V AC Class 1E Load Centers, January 8, 2002

Annual Summary Report of Maintenance Rule Activities, July 31, 2000, to July 31, 2001

Annual Summary Report of Maintenance Rule Activities, July 31, 2001, to August 22, 2002

Essential Cooling Water System Significance Basis Document

3Q159MS0034, “Specification for Standby Diesel Generators,” Revision 5

ESF Diesel Generator Lube Oil and Jacket Water Heat Exchanger Inspection Results

STPS-36, “Performance, Sound, and Vibration Test Report for Essential Water Chiller,” June 7, 1985

Specification 3V259VS0005, “Specification for safety Class Air Handling Units,” Revision 2

Specification 3V249VS1007, “Specification for Safety Class Centrifugal Water Chillers,” Revision 4

Operability/Reportability Review 03-3983-2, "Uninsulated Safety Injection and Containment Spray Piping in the emergency Core Cooling Pump Room," March 20, 2003

Calculations

MC-6476, “Jacket Water and Lube Oil Cooler Performance,” Revision 9

MC-6482, “Essential Chilled Water/EAB HVAC Design Basis Loads with Capacity of 300 Tons per Train,” Revision 1

MC-6219, “Generic Letter 89-013,” Revision 2

MC-6429, “Essential Chiller Operational Analysis,” Revision 1

MC-06482A, “Essential Chilled Water Minimum Flow Requirements for EAB, CRE, FHB, MAB Coolers,” Revision 0

DCN 9602763 and Calculation 5V120MC5160, “FBH Cooling Load,” Revision 8

Drawing

3V119V22519, “Process Flow Diagram Essential Chilled Water System Train A,” Revision 1

Work Orders

PM99000487	WO399782	WO415095
PM99004474	WO406123	WO423710

ATTACHMENT 2

TI 2515/149: Mitigating System Performance Index Pilot Verification

Inspection Requirements

03.02 Risk Significant Functions

No discrepancies were noted. The licensee correctly identified the risk significant functions for trains within the selected systems. The licensee selected the risk significant functions using the Graded Quality Assurance risk ranking process in accordance with their risk-informed exemption to special treatment requirements. All functions determined to have “high” or “medium” risk significance were included.

03.03 Success Criteria

Each of the above functions had an appropriate success criteria at the train level (none of the reviewed systems had a separable segment below the train level) which were consistent with the licensee’s probabilistic risk assessment (PRA) analysis, Technical Specifications, and design basis documentation. The senior reactor analysts reviewed the INEEL Standardized Plant Analysis Risk Model for South Texas Project, Revision 3 (SPAR model), and the Risk-Informed Inspection Notebook for South Texas Project Nuclear Generating Stations, Units 1 and 2, Revision 1 (Risk-Informed Notebook), to determine if they were consistent with the licensee’s PRA functional success criteria for the Mitigating System Performance Index (MSPI). This comparison is provided in Table 1.

TABLE 1
South Texas Project
Functional Success Criteria

System	**Success Criteria**	**Applicable Transients**	**SPAR**	**Notebook**
AFW	Each train starts and delivers 500 gpm at 1519 psig or greater	All except MBLOCA, LBLOCA, LECH, and ISLOCA	FTS	1/3 MDP or 1/1 TDP
	Each train runs for 24-hour mission time	All except MBLOCA, LBLOCA, LECH, and ISLOCA	FTR	1/3 MDP or 1/1 TDP
	Each train delivers rated flow in 1 minute to its steam generator	All except MBLOCA, LBLOCA, LECH, and ISLOCA	FTS	1/3 MDP or 1/1 TDP
	485,000 gallons available for use with a 4-hour limit to refill if level drops low due to routine leakage	All except MBLOCA, LBLOCA, LECH, and ISLOCA	AFW-TNK-FC-FWST	not modeled

EDG	Each SDG will start and load on the ESF bus in 10 seconds	LOOP	FTS	1/3 SDG
	Each SDG will provide power at 58.8 to 61.2 Hz and 3744 to 4587 volts	LOOP	FTR	1/3 SDG
	Each SDG will deliver 5500 kW	LOOP	FTR	1/3 SDG
	Each SDG will operate fully loaded for 24 hours (mission time)	LOOP	FTR	1/3 SDG
HHSI	HHSI pump will automatically start and inject into the cold leg in 45 seconds	ISLOCA, LEAC, LCCW, MSLB, SGTR, LOOP, LLOCA, MLOCA, SORV, and SLOCA TPCS	FTS	1/3 HHSI trains or ½ remaining trains
	HHSI pump will develop greater than or equal to 1480 psid on recirculation	ISLOCA, LEAC, LCCW, MSLB, SGTR, LOOP, LLOCA, MLOCA, SORV, and SLOCA TPCS	FTR	1/3 HHSI trains or ½ remaining trains
	HHSI pump will deliver greater than or equal to 1470 gpm, but less than or equal to 1620 gpm at full flow	ISLOCA, LEAC, LCCW, MSLB, SGTR, LOOP, LLOCA, MLOCA, SORV, and SLOCA TPCS	FTR	1/3 HHSI trains or ½ remaining trains
	The RWST has 485,000 gallons available for use with a 1-hour limit to refill if level drops low due to routine leakage	ISLOCA, LEAC, LCCW, MSLB, SGTR, LOOP, LLOCA, MLOCA, SORV, and SLOCA TPCS	HPI-TNK-FC-FWST	not modeled
	RWST boron concentration is greater than or equal to 2800 but less than or equal to 3000 ppm with a 1-hour limit to restore if concentration deviates	ISLOCA, LEAC, LCCW, MSLB, SGTR, LOOP, LLOCA, MLOCA, SORV, and SLOCA TPCS	HPI-TNK-FC-FWST	not modeled

	System will swap to containment sump suction prior to 30,000 gallon level in the RWST	ISLOCA, LEAC, LCCW, MSLB, SGTR, LOOP, LLOCA, MLOCA, SORV, and SLOCA TPCS	HPI-MOV-00-1A/B/C	LPR/HPR
	Manual control and reset available	ISLOCA, LEAC, LCCW, MSLB, SGTR, LOOP, LLOCA, MLOCA, SORV, and SLOCA TPCS	Note 1	Note 1
LHSI	LHSI pump will automatically start and inject into the cold leg in 65 seconds	TPCS, SLOCA, SORV, MLOCA, LLOCA, LOOP, SGTR, MSLB, LEAC, and ISLOCA	FTS	½ remaining LHSI trains
	LHSI pump will deliver greater than or equal to 286 psid on recirculation	TPCS, SLOCA, SORV, MLOCA, LLOCA, LOOP, SGTR, MSLB, LEAC, and ISLOCA	FTR	½ remaining LHSI trains
	LHSI pump will deliver greater than or equal to 2550 gpm, but less than or equal to 2800 gpm at full flow	TPCS, SLOCA, SORV, MLOCA, LLOCA, LOOP, SGTR, MSLB, LEAC, and ISLOCA	FTR	½ remaining LHSI trains
	The RWST has 485,000 gallons available for use with a 1-hour limit to refill if level drops low due to routine leakage	TPCS, SLOCA, SORV, MLOCA, LLOCA, LOOP, SGTR, MSLB, LEAC, and ISLOCA	HPI-TNK-FC-FWST	not modeled
	RWST boron concentration is greater than or equal to 2800 gpm, but less than or equal to 3000 ppm with a 1-hour limit to restore if concentration deviates	TPCS, SLOCA, SORV, MLOCA, LLOCA, LOOP, SGTR, MSLB, LEAC, and ISLOCA	HPI-TNK-FC-FWST	not modeled
	System will swap to containment sump suction prior to 30,000 gallon level in the RWST	TPCS, SLOCA, SORV, MLOCA, LLOCA, LOOP, SGTR, MSLB, LEAC, and ISLOCA	LPI-MOV-CC-16A/B/C	LPR/HPR
	Manual control and reset available	TPCS, SLOCA, SORV, MLOCA, LLOCA, LOOP, SGTR, MSLB, LEAC, and ISLOCA	Note 1	Note 1

CCW	Pump starts and provides 4370 gpm flow to the RHR heat exchanger in 15 minutes	ALL	FTS	1/3 CCW trains
	Provide flow through the CCW/ECW heat exchanger	ALL	FTR	1/3 CCW trains
ECW	Automatically provide water to served components at less than or equal to 99°F for 24 hours (mission time)	ALL	FTR	1/3 ECW trains
	Provide 634 gpm flow to SDG with 5 minutes	ALL	FTS	1/3 ECW trains
	Provide 6000 gpm flow to the CCW heat exchanger within 15 minutes	ALL	FTR	1/3 ECW trains
Note 1: These are operability criteria that are inherently implied in the notebook/SPAR modeling of functionality.				

03.04 Unreliability Boundary Definitions

The inspectors confirmed that the licensee's definition of the system/train boundaries and the identification of active components was in accordance with the guidance, with one exception: the guidance specified that diesels should include the starting air receivers, whereas the licensee specified that only one was required. The licensee pointed out that the guidance also referred to this equipment in a singular case, so they submitted a Frequently Asked Question to clarify the guidance. The inspectors also confirmed that the active components were accounted for in the site-specific spreadsheet and that the spreadsheet used industry reliability values in accordance with the guidance, with one exception: the licensee used the higher unreliability values from Table 2 under high pressure safety injection for their RHR function. This was done because these values more closely approximated the site's reliability history. The inspectors noted that this would have the effect of establishing a baseline which was higher than the actual site and industry averages, so a more unreliable performance would be permitted in the future. The licensee agreed that using a different value than explicitly intended in the guidance should be done only after getting approval, so the licensee submitted a Frequently Asked Question on this topic.

Additionally, the senior reactor analysts reviewed the INEEL Standardized Plant Analysis Risk Model for South Texas Project, Revision 3 (SPAR model) and the Risk-Informed Inspection Notebook for South Texas Project Nuclear Generating Stations, Units 1 and 2, Revision 1 (Risk-Informed Notebook) to determine if they were complete and consistent with the licensee's list of active components for the MSPI. This comparison is provided in Table 2.

TABLE 2 South Texas Project Active Components				
System/Train	**Component**	**Function**	**SPAR Basic Event**	**Notebook Location**
AFW-A	Pump M/D AFWP-11(21)	Motor feed pump	AFW-MDP-**-P11(21)[2]	Table 2
	Valve AF-MOV-0048	Discharge valve	not modeled	not modeled
AFW-B	Pump M/D AFWP-12(22)	Motor feed pump	AFW-MDP-**-P12(22)[2]	Table 2
	Valve AF-MOV-0065	Discharge valve	not modeled	not modeled
AFW-C	Pump M/D AFWP-13(23)	Motor feed pump	AFW-MDP-**-P13(23)[2]	Table 2
	Valve AF-MOV-0085	Discharge valve	not modeled	not modeled
AFW-D	Pump T/D AFWP-14(24)	Turbine injection pump	AFW-TDP-**-P14(24)[2]	Table 2
	Valve AF-MOV-0019	Discharge valve	not modeled	not modeled
	Valve MS-MOV-0514	Steam admission valve	AFW-MOV-CC-514 [2]	Table 3[1]
EDG-A	Diesel Generator DG-11(21)	Emergency ac power	EPS-DGN-**-DG11(21)[2]	Table 2
EDG-B	Diesel Generator DG-12(22)	Emergency ac power	EPS-DGN-**-DG12(22)[2]	Table 2
EDG-C	Diesel Generator DG-13(23)	Emergency ac power	EPS-DGN-**-DG13(23)[2]	Table 2
HHSI-A	Pump M/D HHSIP-11(21)	Motor injection pump	HPI-MDP-**-P1A [2]	Table 2

	Valve SI-MOV-0016A	Injection valve	not modeled	Table 3[1]
HHSI-B	Pump M/D HHSIP-12(22)	Motor injection pump	HPI-MDP-**-P1B	Table 2
	Valve SI-MOV-0016B	Injection valve	not modeled	Table 3[1]
HHSI-C	Pump M/D HHSIP-13(23)	Motor injection pump	HPI-MDP-**-P1C	Table 2
	Valve SI-MOV-0016C	Injection valve	not modeled	Table 3[1]
LHSI-A	Pump M/D LHSIP-11(21)	Motor injection pump	LPI-MDP-**-P1A [2]	Table 2
	Valve SI-MOV-0016A	Injection valve	not modeled	Table 3[1]
LHSI-B	Pump M/D LHSIP-12(22)	Motor injection pump	LPI-MDP-**-P1B [2]	Table 2
	Valve SI-MOV-0016B	Injection valve	not modeled	Table 3[1]
LHSI-C	Pump M/D LHSIP-13(23)	Motor injection pump	LPI-MDP-**-P1C [2]	Table 2
	Valve SI-MOV-0016C	Injection valve	not modeled	Table 3[1]
CCW-A	Pump M/D CCWP-11(21)	Motor cooling pump	CCW-MDP-**-P1A[2]	Table 2
	Valve CC-FV-4531	Discharge valve	not modeled	Table 3[1]
CCW-B	Pump M/D CCWP-12(22)	Motor cooling pump	CCW-MDP-**-P1B [2]	Table 2
	Valve CC-FV-4548	Discharge valve	not modeled	Table 3[1]

CCW-C	Pump M/D CCWP-13(23)	Motor cooling pump	CCW-MDP-**-P1C [2]	Table 2
	Valve CC-FV-4565	Discharge valve	not modeled	Table 3[1]
ECW-A	Pump M/D ECWP-11(21)	Motor cooling pump	ECW-MDP-**-P1A [2]	Table 2
	Valve EW-MOV-0121	Discharge valve	not modeled	Table 3[1]
ECW-B	Pump M/D ECWP-12(22)	Motor cooling pump	ECW-MDP-**-P1B [2]	Table 2
	Valve EW-MOV-0137	Discharge valve	not modeled	Table 3[1]
ECW-C	Pump M/D ECWP-13(23)	Motor cooling pump	ECW-MDP-**-P1C [2]	Table 2
	Valve EW-MOV-0151	Discharge valve	not modeled	Table 3[1]
[1] Valves are not specifically discussed but are included as part of train functionality [2]The “**” is replaced by FS, FR, TM (one each)				

03.05 Train/Segment Unavailability Boundary Definition

No discrepancies were noted. The licensee appropriately defined the scope of the trains being monitored for unavailability within the selected systems.

03.06 Entry of Baseline Data - Planned Unavailability

A number of minor discrepancies were noted and corrected by the licensee.

03.07 Entry of Baseline Data - Unplanned Unavailability

The inspectors identified that the licensee had reported site-specific unavailability data which included both planned and unplanned time, contrary to the guidance. The guidance specified that site-specific planned unavailability and generic industry unplanned unavailability was to be used. The licensee did this because the process of separating the data into the two categories was too time consuming to meet the initial reporting deadline, but expected that the data reported would conservatively overestimate unavailability. The inspectors noted that this would have the effect of establishing a baseline which was higher than actual, which allows a nonconservative bias in future unavailability. During the inspection the licensee removed the unplanned unavailability time and revised the data when the November data was submitted.

03.08 Entry of Baseline Data - Unreliability

No discrepancies were noted.

03.09 Entry of Performance Data - Unavailability

No discrepancies were noted.

03.10 Entry of Performance Data - Unreliability

No discrepancies were noted.

03.11 MSPI Calculation

The analysts reviewed the licensee's MSPI basis documents and spreadsheets to determine the validity of the Fussell-Vesely coefficients used in the MSPI calculation. The following observations were made:

- The staff did not qualify the licensee's updated PRA for use prior to or during the MSPI pilot. Therefore, these line items could not be performed as written.

- All Fussell-Vesely coefficients were greater than zero, indicating that the associated components or trains were modeled in the licensee's PRA.

- A review of a sample of coefficients for each site indicated that the relative significance of the components and/or trains were in keeping with their expected relative risk significance.

- Most Fussell-Vesely coefficients were too small to verify using hand calculations because the associated core damage frequencies were equal out to four significant digits.

- Based on a sample of coefficients, large enough to verify using hand calculations, the Fussell-Vesely coefficients provided by the licensee were consistent with those produced by the licensee's model of record.

- Based on a sample of coefficients, the SPAR model results were within a factor of 5 of the Fussell-Vesely coefficients provided by the licensee.

While gathering information requested by the NRC analysts, licensee analysts discovered the following three modeling errors that affected their calculation of the MSPI:

1. In calculating the ratio of the Fussell-Vesely divided by unreliability, the mission time of the component was inadvertently omitted in calculating the assumed unreliability of the components. This made the ratio larger than it should have been, because the

Fussell-Vesely was divided by the failure rate per hour instead of the larger failure rate per mission time, tending to make the reported MSPI value larger than it should have been.

2. The licensee's model had previously combined failure modes for individual components such as fail-to-start and fail-to-run. While providing valid core damage frequency results, when used to calculate the Fussell-Vesely of the specific failure mode, this generated results that were too large. However, this data also decreased the plant unreliability factor for the failure mode. Therefore, the MSPI value may have been higher or lower than initially reported.

3. The licensee's analysts determined that they had been using the Fussell-Vesely values for the split fractions related to unavailability instead of those of the top event. This resulted in slightly higher Fussell-Vesely values in the MSPI calculations. Therefore, the reported MSPI values were smaller than they should have been.

The licensee corrected these errors and revised the MSPI data. The combined changes in the MSPI values related to the subject errors were small. None of the changes resulted in the MSPI crossing a threshold.

General Comments

The inspectors noted that the licensee had tentatively concluded that they had a number of invalid indicators, according to the definitions in the guidance.

LIST OF ACRONYMS USED IN ATTACHMENT 2

AFW	auxiliary feedwater
CCW	component cooling water
DGN	diesel generator
ECW	essential cooling water
EDG	emergency diesel generator
EPS	electric power system
ESF	engineered safety features
FR	failure to run
FS	failure to start
FTR	failure to run
FTS	failure to start
FWST	feedwater storage tank
HHSI	high head safety injection
HPR	high pressure recirculation
INEEL	Idaho National Engineering and Environmental Laboratory
ISLOCA	intersystem loss of coolant accident
LBLOCA	large-break loss of coolant accident
LCCW	loss of all component cooling water
LEAC	LOOP with loss of one Class 1E 4.16 kV ac bus
LECH	loss of essential chilled water

LHSI	low head safety injection
LOOP	loss of offsite power
LPI	low pressure injection
LPR	low pressure recirculation
M/D	motor-driven
MBLOCA	medium-break loss of coolant accident
MDP	motor-driven pump
MOV	motor-operated valve
MSLB	main steam line break
MSPI	mitigation systems performance indicator
PRA	probabilistic risk assessment
RHR	residual heat removal system
RWST	refueling water storage tank
SBLOCA	small-break loss of coolant accident
SDG	standby diesel generator
SGTR	steam generator tube rupture
SI	safety injection
SORV	stuck open relief valve
TDP	turbine-driven pump
TM	test and maintenance
TNK	tank
TPCS	transient with loss of power conversion system