ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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Report No.:	50-498/99-18 50-499/99-18
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
Dates:	September 19 through November 6, 1999
Inspectors:	Neil F. O'Keefe, Senior Resident Inspector Wayne C. Sifre, Resident Inspector Gilbert L. Guerra, Resident Inspector
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ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

South Texas Project Electric Generating Station, Units 1 and 2
NRC Inspection Report No. 50-498/99-18; 50-499/99-18

This inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 7-week period of resident inspection.

Operations

- Inspectors identified several problems with poor configuration control. A lock was not reinstalled on a motor-operated valve breaker following maintenance to ensure the valve was not a source for a high energy line break. Other administrative controls were adequate to prevent inappropriate operation of the valve and no violation occurred. Operators failed to repressurize the control air header for Standby Diesel Generator 23 following maintenance despite having an annunciator indicating the abnormal condition. As a result, the diesel tripped when it was started for postmaintenance testing. No violation occurred because the diesel was still out of service. Inspectors identified 37 motor control center switches, labeled as spares, which were in the ON position despite having no procedure to direct them to be placed in that position. The switches were energized but not connected to any load, so no safety issue existed (Sections O1.1 and O2.1).

- Inspectors identified that Unit 1 operators crosstied safety Motor Control Centers E1A1 and E1A2, but failed to understand the requirements of and enter Technical Specification 3.8.3.1, Action a. The condition existed briefly during postmaintenance testing of the crosstie breaker, so the action statement was not violated (Section O1.1).

- Operators performed well while shutting Unit 2 down for the refueling outage and during the subsequent startup. Reactivity changes were carefully performed and followed the profiles planned for the evolutions. Operations were well supervised and focused on safe practices, both in the control room and in the field. Peer checking was consistently performed. The plant equipment performed as expected (Sections O1.2 and O1.4).

- A controller power supply for both moisture separator reheaters failed. This caused the loss of reheat steam because the redundant power supply, although set per vendor instructions, was set too low to function properly. Operators performed a rapid power reduction to protect the main turbine blades from moisture damage. The operators' response was complicated by five steam plant motor operated valves which were mechanically bound or had limit switch problems that required manual action. Material condition deficiencies of balance of plant equipment both initiated and complicated this event (Section 01.3).

- Reactor coolant system reduced inventory and midloop operations were performed in a controlled manner by operators who were knowledgeable and experienced in the evolution. Excellent supervisory oversight helped to effectively coordinate site activities and ensure the safe execution of this important evolution. The licensee conservatively stopped work on all jobs that had the potential to impact the evolution. Contingency actions were briefed in detail and assigned to specific personnel, and venting equipment

was installed for immediate use (Section O1.5).

- Operators inadvertently rendered Standby Diesel Generator 22 inoperable while tagging out a portion of the starting air system for maintenance. A drawing error was not recognized until starting air was isolated to the entire system. Technical Specification requirements were quickly satisfied when the error was recognized and no violation occurred. This issue was documented in Condition Report 99-13106. The inspectors determined that this was the first time the drawing error was identified or impacted system operability. Failure to have accurate system drawings was a violation of 10 CFR Part 50, Appendix B, Criterion V. However, this licensee identified and corrected violation will not be cited in accordance with Section VII.B.1.a of the Enforcement Policy (Section O3.1).

- The inspectors used TI-142 to confirm that the licensee had adequately searched for potential draindown paths that could be created by operator error or equipment failures and which could lead to a common-cause failure of residual heat removal and emergency core cooling system pumps. The inspectors determined that the licensee had adequate administrative controls in place to reduce the likelihood of an inadvertent draindown of the reactor coolant system (Section O3.2).

- The inspectors identified one instance where the licensee inserted bottom mounted instrument thimbles into the core, a core alteration per the licensee's existing Technical Specifications, without having containment integrity, communications with the control room established, or containment ventilation isolation operable. The licensee had used MERITS (a version of Improved Technical Specifications) to procedurally define what constituted a core alteration in conflict with their own Technical Specifications. The safety significance of this was low because Improved Technical Specifications permit this action. Failure to satisfy Technical Specification requirements for core alterations was a violation. As a result of the inspectors' findings, the licensee wrote Condition Report 99-14640 to address the violation and made the required report to the NRC. This nonrepetitive violation will not be cited in accordance with Section VII.B.1.a of the Enforcement Policy (Section O4.1)

- The licensee conducted a thorough self-assessment of plant operations. The assessment, performed by an experienced, multidisciplined team of seven site people and seven industry peers, was broad in scope. The findings were considered to be self-critical and were consistent with NRC observations (Section O7.1).

Maintenance

- The licensee identified a steam leak in a balance of plant instrument line that caused the instruments to sense less than actual steam line pressure. While planning a repair, the leak degraded to the point where the affected instruments opened turbine drains. Despite prompt operator action to limit the magnitude of the transient, this material deficiency in non-safety equipment caused an uncontrolled reactor power increase from 99 percent to 100.15 percent (Section M1.2).

- Following a transient caused by a leaking steam pressure instrument line in Unit 1, a

temporary modification was installed to bypass the leaking line. Maintenance personnel valved in the pressure instruments, causing power to increase from 100 percent to 101.97 percent before operator action turned power. The inspectors concluded that the licensee's temporary modification package and the associated work package did not provide precautions to properly restore the instrument line to service. Operator response was quick and effective. Stringent controls and precautions for work with the potential to affect reactor power were not implemented (Section M1.2).

- The inspectors observed that fuel handling activities during the Unit 2 outage were performed in a careful manner. Improved emphasis on attention to detail during fuel positioning was effective in reversing a previously observed declining trend in performance in this area (Section M1.3).

- The inspectors determined that the licensee's monthly turbine-driven auxiliary feedwater pump operability surveillance procedure had the potential to mask an inoperable condition. The inspectors observed that the governor was somewhat sensitive to room temperature and sometimes required adjustments. The procedure directed a speed adjustment to the test reference point without recording and evaluating the as-found speed. The inspectors determined that the turbine-driven auxiliary feedwater pump was operable (Section M3.1).

Engineering

- The inspectors reviewed the 50.59 evaluation and work documents for performing freeze seals and repairs to bottom mounted instrument thimble seals. The inspectors identified that some of the assumed plant conditions used to evaluate the job were not translated into prerequisites in the work documents that would have ensured that the 50.59 evaluation remained valid (Section E2.1).

Plant Support

- The cooldown of Unit 2 was appropriately delayed when chemistry sample results for reactor coolant system boron concentration did not agree with chemical additions. Operations and chemistry personnel coordinated well. Chemistry personnel thoroughly evaluated sources of dilution and analytical error before concluding that the problem was related to analytical limitations in the lab equipment. The cooldown was performed only when proper shutdown margin was confirmed (Section O1.2).

- The highly radioactive Unit 2 core barrel was successfully removed for inservice inspection using excellent planning and dose controls. The job was completed with minimal dose and without incident. Health Physics performance during the Unit 2 refueling outage was consistent with the good performance of the prior Unit 1 outage (Sections R1.1 and R1.2).

Report Details

Summary of Plant Status

Unit 1 started this inspection period at 100 percent power. On September 24 and 25, the unit experienced two small uncontrolled power increases due to instrumentation problems in the secondary steam system.

Unit 2 began this inspection period at full power. The unit entered end-of-cycle coastdown on September 25. On October 10, the unit experienced a controller failure that removed reheat steam from the moisture separator reheaters and forced a power reduction to prevent moisture in the main turbine. Power was reduced to about 57 percent before reheat steam was restored. The unit was returned to 86 percent power later the same day. The unit was shut down for a scheduled refueling outage on October 13. The unit was brought critical on November 6 and was operating at low power for physics testing at the conclusion of this inspection.

I. Operations

O1 Conduct of Operations

O1. 1 Conduct of Operations (71707)

The inspectors used Inspection Procedure 71707 to conduct frequent reviews of ongoing plant operations. In general, the conduct of operations was focused and safety conscious. Specific comments and noteworthy events are discussed below.

During the Unit 2 outage, the inspectors reviewed the licensee's implementation of cold overpressure mitigation requirements. During each phase of the outage, operators properly implemented and logged vent paths or relief capabilities which satisfied Technical Specification requirements.

During a log review, the inspectors identified that Unit 1 operators failed to enter Technical Specification 3.8.3.1, Action a, when they crosstied Motor Control Centers E1A1 and E1A2. This condition existed briefly for postmaintenance testing of the crosstie breaker, so the Technical Specification action requirements were not violated. The inspectors found that the Technical Specification was reviewed but not understood by the shift supervision. This issue was subsequently documented in Condition Report 99-13890.

Also during a log review, inspectors identified that Unit 2 operators did not document declaring Source Range Nuclear Instrument 32 inoperable while performing Plant Surveillance Procedure 0PSP05-NI-0032A on October 13. The limiting condition for operation remained satisfied, so no violation occurred. The inspectors determined that the operators recognized that the surveillance rendered the instrument inoperable, but had not logged it because they knew the requirements were satisfied. This was considered to be a poor practice.

On October 26, 1999, operators did not repressurize the control air header for Standby

Diesel Generator 23, causing Diesel Generator 23 to trip during postmodification testing and troubleshooting. Plant Operating Procedure OPOP02-DG-0003, Revision 23, "Emergency Diesel Generator 13(23)," required operators to ensure that all lamp box annunciators had been properly evaluated. Operators inappropriately concluded that the cause for each existing annunciator was known, when in fact low control air pressure was causing the "DG Low Air Pressure" annunciator to be lit. Procedure 0POP09-AN-0106, "Annunciator Lampbox 2-106 Response Instructions," Revision 7, directed repressurizing of the control air header, but the annunciator procedure was not consulted. The system was already inoperable for maintenance when this event occurred, so no violation occurred. However, this was considered to be an example of inattention to detail and poor configuration control.

O1.2 Observations of the Unit 2 Shutdown for Refueling (71707)

Inspectors observed the power reduction and reactor shutdown on October 12-13. Operators did an excellent job in briefing and performing the shutdown. Operations were well supervised and focused on safe practices, both in the control room and in the field. Peer checking was consistently performed. The plant equipment performed as expected during the shutdown, with the exception of minor problems with each of the three steam generator feed pumps. The primary plant was degassed with some difficulty due to unfamiliarity with this infrequently performed procedure, but this did not impact the shutdown evolution. After the main generator breaker was opened, the control room became crowded with surveillance team personnel performing multiple tests. Control room composure was compromised at times because of this.

Reactor engineering personnel provided excellent support during the shutdown. They participated in reactivity briefs and provided core predictions throughout the shutdown. Following shutdown, reactor engineers successfully performed rod drop testing in a crisp manner, effectively minimizing the time that digital rod position indication was inoperable.

The start of plant cooldown was appropriately delayed when chemistry sample results for reactor coolant system boron concentration did not agree with values that operators calculated based on the chemical additions operators had made. Technical Specifications required that shutdown margin be verified before adding positive reactivity due to cooling down. Operations and chemistry personnel coordinated well while the possible causes were investigated. The licensee determined that chemistry technicians used the wrong sample size for the expected concentration, based on incomplete communications with operators. This caused the automatic titrator to reach its titrant limit without reaching the titration endpoint and to report low sample results.

O1.3 Unit 2 Power Reduction Due to Moisture Separator Reheater Controller

a. Inspection Scope (71707, 62707)

On October 10, Unit 2 lost power to the moisture separator reheater controller, so the main steam supply valves closed. Without reheat steam, steam temperature to the low pressure turbines dropped below 500°F, requiring operators to lower power below

50 percent by procedure to avoid turbine erosion. Power was lowered to 57 percent before steam was restored manually. The inspectors discussed this event with operations, maintenance, and engineering personnel, and reviewed logs and condition reports associated with the event.

b. Observations and Findings

Operators responded appropriately to this event. Reactor engineering personnel responded to the site to assist and provided good support in returning the unit to 86 percent power and continuing coastdown after the problem was corrected. The inspectors noted that control room logs documenting the event were sketchy and included numerous late entries.

The event was initiated by a failure of a controller power supply. A backup power supply would have allowed manual control of reheat steam, but the licensee determined that, while it was set per vendor instructions, it was set too low to function. The event was exacerbated by the failure of five motor-operated steam plant valves to open on demand, requiring operators to manually operate the valves when the control circuit was restored. Three of the valves that did not open electrically were mechanically bound and opened electrically after they were manually lifted from their seat. The remaining two valves had close limit switches that did not operate properly and prevented the valves from reopening. Six condition reports were written to document the event and the multiple material deficiencies that were discovered as a result.

The inspectors also asked if the system was covered in the maintenance rule program. Licensee engineers stated that the system was not covered, but would be considered for inclusion during the next expert panel meeting as a result of this event. Corrective actions, including revision of the vendor manual with a higher voltage setting, were implemented during the refueling outage.

c. Conclusions

A controller power supply for both moisture separator reheaters failed. This caused the loss of reheat steam because the redundant power supply, although set per vendor instructions, was set too low to function properly. Operators performed a rapid power reduction to protect the main turbine blades from moisture damage. The operators' response was complicated by five steam plant motor operated valves which were mechanically bound or had limit switch problems that required manual action. Material condition deficiencies of balance of plant equipment both initiated and complicated this event.

O1.4 Unit 2 Startup Observations (71707)

Unit 2 plant heatup and reactor startup on November 5-6 were conducted well. Operational mode changes were deliberately performed in accordance with plant procedures. Reactor operators properly responded to changing plant conditions. Extra reactor operators and senior reactor operators were utilized to distribute the workload. For example, during the reactor startup, a dedicated senior reactor operator and a

reactor operator controlled reactivity changes with guidance from reactor engineers. The Unit Supervisor effectively controlled the rest of the plant operations while coordinating with the desired reactivity changes. Good engineering support was provided during the reactor startup. Reactor engineering support continued with low power physics testing.

O1.5 Observation of Unit 2 Reactor Coolant System Reduced Inventory Operations

a. Inspection Scope (62707, 71707)

The inspectors maintained continuous onsite coverage during midloop operations in Unit 2 on October 15-16 and November 3. The inspectors observed preparations and briefings, walked down temporary systems for water level indication and vacuum filling, and verified that personnel designated to perform contingency actions were trained and stationed with necessary equipment. Procedures, planning, and oversight were evaluated prior to reduced inventory operations. Core decay heat and time to boil calculations were compared to operational assumptions in procedures governing this evolution.

b. Observations and Findings

Shutdown Risk Assessment Group Readiness Review

The October 15 Shutdown Risk Assessment Group midloop readiness review meeting discussed the readiness of the site to conduct reduced inventory operations in great detail. All work planned for the period of reduced inventory was discussed with work group supervisors to determine the risk impact. Weather predictions and the status of the operating unit were also reviewed for impact. All surveillance testing was stopped during the period of reduced inventory. Work in and above the area of sensitive equipment was challenged. Several items were conservatively deferred until after the period of reduced inventory as a result of this review. Additionally, completion of construction of steam generator tents was designated as a prerequisite to starting draindown to ensure that the amount of time spent in a reduced inventory condition was minimized.

Preparations

The licensee conducted thorough prejob briefs for all appropriate personnel. Contingency actions were assigned to specific personnel, and contingency equipment (e.g., residual heat removal system vent rigs) was installed and inventoried. Quality Assurance personnel were assigned to monitor preparations and the evolution itself. Site awareness was maintained at a high level through a variety of signs, periodic announcements, and TV messages. The operators received classroom and simulator training on the evolution and contingency actions, as well as industry lessons learned. The licensee removed work authority and evaluated every job to ensure there was no impact to safely performing midloop, reauthorizing only jobs with no potential impact.

The inspectors observed that the licensee's procedures governing this complex evolution were detailed. The procedures were found to effectively implement corrective actions committed to in response to site and industry events related to midloop operations.

Performance of the Evolution

Supervisory oversight of the evolution was excellent. Outage management actively provided important coordination of all site activities to ensure that equipment important for midloop operations or contingency actions were maintained available. Senior licensed operators were assigned to supervise the operational aspects of the evolution and coordinate entry into the primary side of each steam generator to install or remove nozzle dams.

Operators were found to be very knowledgeable and experienced with midloop operation. During the evolution, operators alertly monitored all pertinent instrumentation and performed frequent verification of parameters among diverse instruments. Licensed operators patrolled all areas of the plant to ensure work did not interfere with the safe completion of reduced inventory operations.

c. Conclusions

Reactor coolant system reduced inventory and midloop operations were performed in a controlled manner by operators who were knowledgeable and experienced in the evolution. Excellent supervisory oversight helped to effectively coordinate site activities and ensure the safe execution of this important evolution. The licensee conservatively stopped work on all jobs that had the potential to impact the evolution. Contingency actions were briefed in detail and assigned to specific personnel, and venting equipment was installed for immediate use.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature (ESF) Systems Walked Down

a. Inspection Scope (71707)

The inspectors used Inspection Procedure 71707 to walk down accessible portions of the following ESF systems:

- Safety Batteries and Emergency DC Distribution, Channels I, II, III, and IV (Unit 1)
- Component Cooling Water, Trains A, B, C (Unit 2)

b. Observations and Findings

Equipment operability and material condition were acceptable in all cases. The inspectors verified that the systems were aligned properly for the existing mode of operation. The inspectors conducted daily control board walkdowns to verify that ESF systems were aligned as required by Technical Specification for the existing operating mode, that instrumentation was operating correctly, and that power was available.

The inspectors identified that rubber surgical gloves were left on the Train C high head safety injection pump motor base, blocking one motor vent. This was considered to be an isolated example of poor housekeeping.

The inspectors found many Unit 1 motor control center switches labeled as spares which were in the ON position. Of these, 31 were in safety train buses and six were in nonsafety buses. This was reported to shift supervisor, but no Condition Report was written. This practice was indicative of poor configuration control since there was no procedure to direct turning the switches on. The switches were energized but not connected to any load, so no safety issue existed.

The inspectors found the padlock off of Motor Control Center Switch E1A1/C2, which controlled power to Residual Heat Removal Valve MOV-0066A. Lineup 23 of Plant Operating Procedure 0POP02-RH-0001 required the switch to be locked OFF during operation to protect against an unanalyzed high energy line break. Condition Report 99-14050 was written and the lock was reinstalled. The inspectors concluded that the licensee's procedures were adequate to prevent inadvertently energizing and repositioning the valve, so there was no direct safety significance for this issue. However, the licensee concluded that the lock had not been restored when a tagout was cleared, indicating an additional problem with configuration control.

c. Conclusions

Equipment operability and material condition of the ESF systems walkdown were acceptable in all cases.

O3 Operations Procedures and Documentation

O3.1 Standby Diesel Generator 22 Inadvertently Rendered Inoperable Due to Drawing Error (71707)

On September 20, a nonlicensed operator assigned to hang tags on Standby Diesel Generator (SDG) 22 recognized that the tags removed starting air to both sides of the engine. The system had dual sets of compressors, driers, receivers, and cross-connected air start headers. The tagout was intended to isolate and vent one-half of the system while the remaining half-system was maintained in a condition which would start the diesel engine. However, after hanging the tags, the operator recognized that the compressor, drier, and receiver from one side and the air header from the other side

had been isolated. The control room was notified, the diesel was immediately declared inoperable, and Technical Specification actions were satisfied within the required action statement times.

The licensee identified that the drawing used to set the isolation boundaries was divided into two sheets. The system was divided on the drawings at the point in the system where the receivers discharged to the headers. Each line incorrectly referred to the location of the opposite header on the second sheet. The licensee identified that similar drawings for SDG 23 contained the same error. The licensee had not previously used this method of isolation. This issue was documented in Condition Report 99-13106, and the drawings were corrected promptly. The inspectors determined that this was the first time the drawing error was identified or impacted system operability. Failure to have accurate system drawings for SDGs 22 and 23 was a violation of 10 CFR Part 50, Appendix B, Criterion V. This licensee-identified and corrected violation will not be cited in accordance with Section VII.B.1.a of the Enforcement Policy (NCV 499/99018-01)

O3.2 Prevention of Draindown During Shutdown and Common-Mode Failure

a. Inspection Scope (TI 2515/142)

The inspectors reviewed the licensee's response to Generic Letter 98-02, "Loss of Reactor Coolant Inventory and Associated Potential for Loss of Emergency Mitigation Functions While in a Shutdown Condition." The inspectors also reviewed the licensee's procedures and administrative controls governing the operation of the residual heat removal system (RHR), emergency core cooling system (ECCS), and piping and instrumentation drawings for common failure modes.

b. Observations and Findings

The licensee's response to Generic Letter 98-02 concluded that sufficient controls were in place to ensure that an inadvertent reactor coolant system draindown and common cause failure of the emergency core cooling system would not occur at the South Texas Project. The South Texas Project utilizes three trains of RHR and ECCS. The high head safety injection pumps, low head safety injection pumps, and containment spray pumps take suction from a common header connected to the refueling water storage tank, each with their own isolation valves. The RHR pumps do not take suction from this header. RHR Trains B and C share a cross-connect on the discharge side of the pumps for reactor cavity draindown. Each of these trains include two normally locked closed containment insolation valves on the drain line.

The licensee's systems include the following design and administrative controls: pressure interlocked motor-operated valves on the RHR suction lines, two check valves on the RHR discharge lines, Technical Specifications allowing reactor coolant system draindown only in Modes 5 or 6, Technical Specification surveillance requirements for system lineup, and an equipment clearance order program controlling valve positions.

c. Conclusions

The inspectors confirmed that the licensee had adequately searched for potential draindown paths that could be created by operator error or equipment failures and which could lead to a common-cause failure of RHR and ECCS pumps. The inspectors determined that the licensee had adequate administrative controls in place to reduce the likelihood of an inadvertent draindown of the reactor coolant system.

O4 Operator Knowledge and Performance

O4.1 Bottom Mounted Instrument Thimbles Inserted in Core Without Satisfying Conditions for Core Alterations (71707)

In preparation for the Unit 2 refueling outage, the inspectors reviewed condition reports related to previous outage issues. The licensee had written Condition Report 99-9620 requesting a reportability review for inserting the incore thimbles into the core without having Technical Specifications core alteration requirements satisfied during Unit 1 refueling outage in the spring of 1999. Specifically, containment purge automatic isolation was inoperable, there was no direct communication between the refueling station and the control room, and the reactor containment building equipment hatch was open. The licensee had concluded that the issue was not reportable by using the definition of core alteration in MERITS (a version of Improved Technical Specifications) which states that a core alteration is the movement of any component in the reactor vessel with fuel in the core and the vessel head removed that could affect reactivity. However, the licensee's Technical Specifications define a core alteration as the movement of any component in the reactor vessel with fuel in the core and the vessel head removed.

The inspectors discussed the issue with NRR and determined that the movement of incore thimbles was a core alteration per the licensee's existing Technical Specifications. Technical Specification 3.9.4.a requires in part that the equipment door be closed and held in place by a minimum of four bolts during core alterations. Technical Specification 3.9.5 requires direct communication between the refueling station and the control room during core alterations. Technical Specification 3.9.9 requires the containment ventilation isolation system be operable during core alterations or that each containment purge and exhaust penetration is secured. The performance of core alterations without satisfying the above conditions was a violation. As a result of the inspector's findings, the licensee wrote Condition Report 99-14640 to address the violation and made the required report to the NRC. This nonrepetitive violation will not be cited in accordance with Section VII.B.1.a of the Enforcement Policy (NCV 498/99018-02).

O7 Quality Assurance in Operations

O7.1 Operations Self-Assessment

a. Inspection Scope (71707)

The inspectors reviewed the results of the Operations Self-assessment Report and discussed the conclusions with operations management.

b. Observations and Findings

The self-assessment was conducted the week of September 13, 1999, by a group of seven STP employees and seven industry peers. The STP members represented the Quality, Operations, Engineering, and Training organizations. The assessment was quite broad in scope, covering organizational/administrative effectiveness, work activity performance, work environment, knowledge and training, corrective action implementation, and material condition.

The assessment team concluded that overall operations performance was satisfactory, but that the process of continuous improvement had fallen off. The assessment identified strengths in the areas of prejob briefings and on-shift training, identifying material condition issues. Areas for improvement included:

- Some examples of untimely corrective actions, including all of the recommendations from the previous Operations self-assessment in early 1999.
- The Reactivity Management Program was not consistently followed and did not include some standards common in the nuclear industry.
- Peer-checking and supervision by licensed operators in the plant were inconsistent, with unclear expectations.
- Procedure usage, documentation timeliness, and feedback timeliness were inconsistent.
- Several industrial safety issues were identified.
- There were a large number (over 30) of material condition tags on the main control boards without an aggressive plan to remedy this situation.

The inspectors concluded that the self-assessment was a good effort. The assessment involved a large number of experienced personnel looking at a broad range of issues that were very relevant to recent operator performance. The examples cited and conclusions reached by the team were consistent with the observations and findings documented in recent resident inspection reports. No safety-significant findings were identified during this review.

Operations management was generally receptive to the conclusions of the assessment. Appropriate corrective actions were planned for many of the issues, although some remained under review.

c. Conclusions

The licensee conducted a thorough self-assessment of plant operations. The assessment, performed by an experienced, multidisciplined team of seven site people and seven industry peers, was broad in scope. The findings were considered to be self-critical and were consistent with NRC observations.

O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) Licensee Event Report 499/99005-00: ESF actuation following a loss of power to Standby Transformer 2 due to electrical fault.

An automatic actuation of ESF components occurred in Unit 2 on August 24, 1999. A loss of power to Standby Buses 2G and 2H occurred when the C-phase lightning arrester failed on the Unit 2 standby transformer. Standby Buses 2G and 2H supply power to the Train B and C ESF buses, respectively. As a result of the power loss to the Train C ESF bus, Standby Diesel Generator 23 started and loaded. Normally, the Train B ESF bus would also have been de-energized; however, Standby Diesel Generator 22 was running for a surveillance test, so the E2B bus remained energized throughout the event.

The suspected cause of the failure was an internal fault due to moisture intrusion. The failure caused a ground on Phase C, causing the operation of the Phase C differential relay to isolate the transformer. Offsite power was restored to the affected ESF buses using the Unit 1 standby transformer while repairs were made to the Unit 2 standby transformer. All lightning arresters were replaced on the Unit 2 standby transformer on September 7, 1999. The only other transformer with the same type of lightning arrester assembly was scheduled for arrester replacement during the next Unit 1 refueling outage. The inspectors determined that corrective action was appropriate and tracked by the licensee's condition reporting system.

II. Maintenance

M1 Conduct of Maintenance

M1.i General Comments: Maintenance and Surveillance Observed

a. Inspection Scope (62707, 61726)

The inspectors observed all or portions of the following maintenance and surveillance activities. For surveillance tests, the procedures were reviewed and compared to the Technical Specification surveillance requirements and bases to ensure the procedures

satisfied the requirements. Maintenance work was reviewed to ensure adequate work instructions were provided and that the work performed was within the scope of the authorized work and was adequately documented. Work practices were also observed. In each case, the impact to equipment operability and applicable Technical Specifications actions were independently verified.

Surveillances observed:

- OPSP03-AF-0007, Revision 14, "Auxiliary Feedwater Pump 14 Inservice Test" (Unit 1)
- OPSP11-MS-0001, Revision 13, "Main Steam Safety Valve Inservice Test" (Unit 1)
- OPSP03-SP-0009A, Revision 13, "Solid State Protection System Actuation Train A Slave Relay Test" (Unit 2)
- OPSP03-SP-0013A, Revision 5, "Train A ESF Actuation and Response Time Test" (Unit 2)
- 0PSP03-SP-0019D, Revision 9, "Turbine Driven Auxiliary Feedwater Actuation and Response Time Test" (Unit 2)
- Full Flow Control Rod Drop Testing (Unit 2)
- PSP03-EA-0002, Revision 6, "ESF Power Availability" (Unit 2)

Maintenance activities observed:

- Core barrel removal for inservice inspection (Unit 2)
- Standby Diesel Generator 23 governor modification and testing (Unit 2)
- Train C motor control center modification work (Unit 2)

b. Observations and Findings

The inspectors observed that surveillance tests were performed utilizing the proper procedures. Prejob briefings were consistently of good quality. Personnel performing surveillance activities had experience with the task. Equipment manipulations during tests were very well controlled by operators. Where required, independent verification techniques were properly conducted. Communications were precise and sufficiently detailed. The inspectors verified that surveillance activities satisfied Technical Specifications requirements.

Surveillance activities observed during the outage were well controlled by reactor operators and conducted in accordance with Technical Specification and procedural requirements. During the Unit 2 outage, a dedicated group of reactor operators was responsible for performing the required surveillances. The reactor operators adequately

controlled the performance of the surveillances utilizing good prejob briefs and three-way communication. No problems were noted in the performance of the required 18-month frequency surveillances.

The inspectors noted that scaffolds used to support outage work in Unit 2 were erected in accordance with station procedures. The operation and seismic qualification of important equipment was not compromised by scaffolds.

The inspectors observed good foreign material control practices at work sites.

c. Conclusions

The maintenance and surveillance activities observed were careful and controlled. High quality prejob briefings were consistently observed. Operators and technicians were very knowledgeable of their assigned tasks.

M1.2 Uncontrolled Power Increases in Unit 1 Due to Leak in Turbine Instrument Line

a. Inspection Scope (62707, 71707, 37551)

On September 24 and 25, Unit 1 experienced two reactor power excursions. The first transient was caused by degradation of a steam leak and the second when restoring the temporary modification to bypass the steam leak. Each of the transients lasted only a few minutes. The inspectors conducted a followup inspection of the events surrounding the transient. Operators were interviewed, and the temporary modification and work instructions were reviewed.

b. Observations and Findings

On September 23, the licensee recognized that steam pressure instruments were not sensing full steam pressure in one of the steam lines from the moisture separator reheater to the low pressure turbines. This was caused by a steam leak in the instrument line which was covered by insulation. Since this was discovered at the end of the work week, the licensee prepared a temporary modification during the weekend with plans to implement it the following Tuesday. Operators were briefed on contingency actions if the situation degraded, since it was recognized that the pressure instruments could cause a steam demand increase if the sensed pressure went too low.

On Friday evening, the pressure signal went to zero, opening the main steam and extraction steam drain valves. This caused reactor power to increase from 99 percent to 100.15 percent. Operators responded as planned to limit the power increase. The licensee then decided to implement the temporary modification to isolate the leak and install tubing to apply pressure from an adjacent steam line to the pressure instruments. The second transient occurred on Saturday morning when steam was valved in to the new modified instrument line. The controller responded to the sudden pressure increase by opening the main steam valves to the de-aerator, causing reactor power to increase from 100 percent to an indicated value of 102.7 percent by heat balance calculation. Control room operators again took appropriate actions to mitigate the

situation. The inspectors noted that the temporary modification package recognized the potential for the steam drains to open, and reasonable precautions were taken to respond to the first transient. However, the licensee's temporary modification package and the associated implementing work package did not provide instructions or precautions to properly restore the instrument line to service.

The licensee evaluated the power increase to determine the actual peak power. For a rapid transient, the most accurate indication was loop differential temperature. This indication peaked at 101.97 percent reactor power. The inspectors reviewed the licensee's analysis and concluded that it was reasonable. Based on this conclusion, the power increase did not violate NRC's guidelines for evaluating transients near the plant's licensed maximum power.

c. Conclusions

The licensee identified a steam leak in a balance of plant instrument line that caused the instruments to sense less than actual steam line pressure. While planning a repair, the leak degraded to the point where the affected instruments opened turbine drains. Despite prompt operator action to limit the magnitude of the transient, this material deficiency in non-safety equipment caused an uncontrolled reactor power increase from 99 percent to 100.15 percent.

The inspectors concluded that the licensee took reasonable precautions to respond to the first transient. However, the licensee's temporary modification package and the associated implementing work package did not provide instructions or precautions to properly restore the instrument line to service. This omission directly caused an uncontrolled power increase above 100 percent power that required operator response to correct. Operator response was quick and effective. Stringent controls and precautions for work with the potential to affect reactor power were not implemented.

M1.3 Fuel Handling Observations (62707, 71707)

The inspectors observed fuel handling activities during core offloading, inspection, and reloading, both inside the reactor building and in the spent fuel pool. The licensee had good communications. A senior reactor operator was stationed as required, with another senior reactor operator observing the operation in the spent fuel pool periodically. All bundles were visually inspected by camera for evidence of damage or foreign material. Forty bundles had their springs tested for a material problem identified by the industry, with good contingency plans if any bad springs were identified.

Inspectors observed that fuel handling was performed in a careful manner. Verifications were performed as required. Plant conditions required by Technical Specifications were established for core alterations. Increased emphasis on attention to detail during fuel positioning was effective in reversing a declining trend in performance in this area.

The inspectors observed one occasion where the fine adjustment handcrank for refueling bridge positioning was not removed before electrically moving the bridge, causing the handcrank to spin at excessive speed. This had been observed during the

previous refueling outage. The personnel hazard from the earlier event had been removed by installing a new bracket, but the licensee did not eliminate the recurring error.

M3 Maintenance Procedures and Documentation

M3.1 Turbine-Driven Auxiliary Feedwater (AFW) Pump Surveillance Did Not Verify As-found Turbine Speed

a. Inspection Scope (61726)

The inspectors observed a monthly operability surveillance of the turbine-driven AFW Pump 14 and reviewed Plant Surveillance Procedure 0PSP03-AF-0007, Revision 14, "Auxiliary Feedwater Pump 14 Inservice Test."

b. Observations and Findings

The inspectors observed that, when turbine-driven AFW Pump 14 was started for the monthly surveillance on September 30, its speed was initially outside the desired speed band. Operators then adjusted the speed to the desired value of 3590 to 3610 rpm per procedure without recording the as-found speed or evaluating whether that speed was acceptable.

The inspectors then questioned the licensee's method of determining the operability of the turbine-driven AFW pump. Specifically, the inspectors noted that, while the surveillance test satisfied the Technical Specification surveillance requirement, it did not fully meet the intent of determining the as-found operability condition of the system. The procedure could allow operators to adjust the turbine speed to the desired value and not recognize that the system was inoperable if the as-found turbine speed was too low to produce the required flow rate.

Discussions with the system engineer revealed that a turbine speed of at least 3545 rpm was required to meet the required flow rate and pressure and that the speed the governor controlled at was somewhat dependent on room temperature. However, the surveillance procedure did not contain this information or guide operators to determine the turbine pump's operability. The inspectors determined that the turbine-driven AFW pump was operable; however, the licensee's surveillance procedure did not provide adequate guidance to operators. The licensee wrote Condition Report 99-15125 to implement a procedure change to the surveillance procedure.

c. Conclusions

The inspectors determined that the licensee's monthly turbine-driven auxiliary feedwater pump operability surveillance procedure had the potential to mask an inoperable condition because it directed a speed adjustment without recording and evaluating the as-found speed. The inspectors observed that the governor was somewhat sensitive to room temperature and sometimes required minor adjustments that were not recorded or

trended. The inspectors determined that the turbine-driven AFW pump was operable.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Review of Freeze Seal Controls for Bottom Mounted Instrument Thimble Guide Tube Repairs

a. Inspection Scope (37551)

The inspectors discussed the planned work with the system engineer and reviewed the following documents:

- Design Change Package 97-2562-25 "BMI Thimble Tube Freeze Sealing," Revision 0
- ST401149-00001-C5X, "Nuclear Plant Freeze Plug Procedures," Revision K
- Work Order 355223, "Replace BMI Thimble Seals and Restore Temporary Leak Repair"
- Work Order 383054, "Perform Freeze Seal Activities to Support Work at the Seal Table for Bottom Mounted Instruments During 2RE07"

b. Observations and Findings

The work was logically divided between the two work orders. The work order used to establish freeze seals as isolation for the work area provided good controls to ensure the location was clearly identified and approved by the Operations Manager and Maintenance Manager. A good contingency plan to respond to a failed freeze seal was provided with the package.

The inspectors considered that the 10 CFR 50.59 evaluation was adequate. However, this evaluation included a number of conditions used as the basis for concluding that installing freeze seals as discussed was safe. The evaluation assumed that the plant was in Mode 5 or 6 and the reactor vented to atmospheric pressure or at a vacuum. These conditions were not translated into prerequisites for either work order. Additionally, the 50.59 clearly required the thimble tubes to be inserted in the core, while Work Order 383054 instructed workers to withdraw the thimble tubes to the refueling position. Withdrawing the thimbles would have resulted in unacceptably high dose rates in the work area. The inspector discussed the licensee's other controls and scheduling methods and was satisfied that work in an unsafe manner would not have been permitted to start. However, the inspectors were concerned that the assumptions used as the basis for the 50.59 evaluation were not translated into work instructions that would have ensured the assumptions remained valid.

c. Conclusions

The inspectors reviewed the 50.59 evaluation and work documents for performing freeze seals and repairs to bottom mounted instrument thimble seals. The inspectors identified some of the assumed plant conditions used to evaluate the job were not translated into prerequisites in the work documents that would have ensured that the 50.59 evaluation remained valid.

E8 Miscellaneous Engineering Issues

E8.1 Completion of Year 2000 (Y2K) Readiness Review (TI 2515/141)

Using Temporary Instruction 2515/141, "Review of Year 2000 Readiness of Computer Systems at Nuclear Power Plants," dated April 13, 1999, the inspectors reviewed aspects of the licensee's Y2K readiness program that were not completed by June 30, 1999. The inspectors reviewed the licensee's Y2K actions for the Procurement and Inventory Control System and the Integrated Computer System. Both were newly installed systems that were procured as Y2K compliant, but the previous systems had not been removed from service. No concerns were identified.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Unit 2 Outage Radiological Work Practice Observations (71750)

The inspectors observed that health physics job coverage was very good during the outage. Doses were below the established goals. Health Physics management was observed to respond effectively to outage challenges. When radworker practices were observed by the licensee to be degrading, a self-assessment was performed in response. This performance trend was publicized site-wide, and management attention was given to promptly reverse it. The results of the self-assessment were to be considered for corrective actions during the next outage.

Health Physics staffing was adequate to support the scheduled work during this outage. Overall contamination control was good, although a slight increase was noted in the number of personnel contaminations over the last outage (with a similar work scope). Housekeeping within the reactor containment building was very good throughout the outage.

R1.2 Core Barrel Removal Observations

a. Inspection Scope (71750)

The inspectors reviewed Plant Maintenance Procedure 0PMP04-RX-0007, Revision 6, "Reactor Vessel Lower Internals Removal and Installation," as well as the associated

work plan, dose projections, and ALARA review. The plans were discussed with health physics personnel and operators. The inspectors then observed the removal of the core barrel.

b. Observations and Findings

The licensee removed the core barrel from the reactor vessel in order to perform required inservice inspections. It was necessary to lift the highly radioactive core barrel partially out of the refueling cavity. The resulting loss of shielding effect from the water in the pool necessitated careful radiological and logistical planning.

Two dry runs of the lift were conducted, which were used to determine the optimum positioning of the crane to deposit the core barrel onto the storage stand. The licensee effectively implemented controls to minimize dose during the evolution. During the evolution, all other work inside containment was stopped and the containment evacuated. Personnel involved in the lift were thoroughly briefed on the job and contingencies. Extensive use of video cameras allowed workers to remain outside the secondary bioshield wall in low dose areas. Polar crane operations were performed utilizing remote controls.

The use of the above controls provided for excellent ALARA planning. Dose for the evolution was 56 mrem, below the budgeted 83 mrem. This was an improvement over the Unit 1 core barrel move which resulted in 93 mrem.

c. Conclusions

The highly radioactive Unit 2 core barrel was successfully removed for inservice inspection using excellent planning and dose controls. The job was completed with minimal dose and without incident.

VI. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management on November 9, 1999. Management personnel acknowledged the findings presented. The inspector asked whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT

PARTIAL LIST OF PERSONS CONTACTED

Licensee

T. Cloninger, Vice President Nuclear Generation
W. Cottle, President and CEO
J. Crenshaw, Manager, Mechanical Fluid Systems Engineering
B. Dowdy, Operations Manager, Unit 2
R. Gangluff, Manager, Chemistry
E. Halpin, Manager, Maintenance
S. Head, Licensing Supervisor
J. Johnson, Manager, Engineering Quality
W. Jump, Outage Manager
A. Kent, Manager, Electrical/Instrumentation and Controls
A. Khosla, Owner Liasion
M. Lashley, Manager, Reliability Engineering
D. Leazar, Manager, Nuclear Fuel and Analysis Department
B. Mackenzie, Manager, Operating Experience Group
G. Parkey, Plant General Manager
J. Phelps, Operations Manager, Unit 1
T. Powell, Manager, Health Physics
P. Serra, Manager, Emergency Response
J. Sheppard, Vice President, Engineering and Technical Services
T. Stroschein, Supervisor, Systems Engineering Department
S. Thomas, Manager, Design Engineering Department
D. Towler, Manager, Operations Quality

NRC

W. Beckner, Chief, Technical Specification Branch, NRR
T. Tjader, Technical Specification Branch, NRR

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92902:	Followup - Maintenance
TI 2515/141:	Review of Year 2000 Readiness of Computer Systems at Nuclear Power Plants
TI 2515/142:	Draindown During Shutdown and Common-Mode Failure (NRC Generic Letter 98-02)

Items Opened and Closed

Opened

50-499/99018-01	NCV	SDG-22 rendered inadvertently inoperable due to drawing error (Section O3.1)
50-498/99018-02	NCV	Thimbles inserted without meeting TS requirements for core alterations (Section O4.1)

Closed

50-499/99005-00	LER	Engineered safety feature actuation following a loss of power to Standby Transformer 2 due to electrical fault (Section O8.1)
50-499/99018-01	NCV	SDG-22 rendered inadvertently inoperable due to drawing error (Section O3.1)
50-498/99018-02	NCV	Thimbles inserted without meeting TS requirements for core alterations (Section O4.1)