UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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ATLANTA, GEORGIA 30303-8931

October 29, 2001

Tennessee Valley Authority
ATTN: Mr. J. A. Scalice
Chief Nuclear Officer and
Executive Vice President
6A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: SEQUOYAH NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 50-327/01-03 AND 50-328/01-03

Dear Mr. Scalice:

On September 29, 2001, the NRC completed an inspection at your Sequoyah Nuclear Plant, Units 1 and 2. The enclosed report presents the results of that inspection which were discussed on September 27, 2001, with Mr. Dennis Koehl and other members of your staff.

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

Based on the results of this inspection, the inspectors identified two findings that had potential safety significance greater than very low significance. These issues do not present an immediate safety concern. In addition, the inspectors identified three issues of very low safety significance (Green), that also were determined to involve violations of NRC requirements. However, because of their very low safety significance and because they have been entered into your corrective action program, the NRC is treating these issues as non-cited violations, in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you deny any non-cited violation in the enclosed report, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at Sequoyah.

Since September 11, 2001, your staff has assumed a heightened level of security based on a series of threat advisories issued by the NRC. Although the NRC is not aware of any specific threat against nuclear facilities, the heightened level of security was recommended for all nuclear power plants and is being maintained due to the uncertainty about the possibility of additional terrorist attacks. The steps recommended by the NRC include increased patrols, augmented security forces and capabilities, additional security posts, heightened coordination with local law enforcement and military authorities, and limited access of personnel and vehicles to the site.

The NRC continues to interact with the Intelligence Community and to communicate information to you and your staff. In addition, the NRC has monitored maintenance and other activities which could relate to the site's security posture.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room 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/NRC/ADAMS/index.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Paul E. Fredrickson, Chief
Reactor Projects Branch 6
Division of Reactor Projects

Docket Nos. 50-327, 50-328
License Nos. DPR-77, DPR-79

Enclosure: NRC Inspection Report 50-327/01-03, 50-328/01-03
w/Attachment

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-327, 50-328
License Nos:	DPR-77, DPR-79
Report No:	50-327/01-03, 50-328/01-03
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Sequoyah Nuclear Plant, Units 1 & 2
Location:	Sequoyah Access Road Soddy-Daisy, TN 37379
Dates:	July 1, 2001 - September 29, 2001
Inspectors:	R. Gibbs, Senior Resident Inspector R. Telson, Resident Inspector R. Carrion, Project Engineer E. Testa, Senior Health Physicist B. Bearden, Reactor Inspector D. Thompson, Physical Security Specialist
Approved by:	P. Fredrickson, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000327-01-03, IR 05000328-01-03, Integrated inspection report, on 7/1/01 - 9/29/01, Tennessee Valley Authority, Sequoyah Nuclear Plant, Units 1 and 2. Surveillance testing, operability evaluations, event follow-up.

The inspection was conducted by resident inspectors, a senior health physicist, a project engineer, a physical security specialist, and a reactor inspector. The inspectors identified two findings that were determined to have potential safety significance greater than very low significance, and also three Green findings, which were also non-cited violations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609 "Significance Determination Process," (SDP). Findings for which the SDP does not apply are indicated by "No Color" or by the severity level of the applicable violation. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at http://www.nrc.gov/NRR/OVERSIGHT/index.html.

A. Inspector Identified Findings

Cornerstone: Mitigating Systems

- TBD. The inspectors identified an unresolved item (URI) involving the failure to implement an emergency diesel generator (EDG) maintenance procedure that would have confirmed identified severe degradation of a piston wrist pin and carrier bearing insert in the 2B-B EDG. Maintenance personnel had incorrectly marked an out-of-specification condition as acceptable, supervisory reviews had failed to detect the error, and the 2B-B EDG was returned to service without evaluation or investigation of the condition. When the error was detected (5 months later), severe component degradation had occurred.

  The finding was determined to have a potential safety significance greater than very low significance because (1) the degraded condition had credibly affected the function of the 2B-B EDG, (2) of the high safety importance of EDGs, (3) the maintenance error was not detected until severe component degradation had already occurred, (4) a second EDG (1A-A) was similarly and concurrently impacted, (5) industry operating experience and the diesel engine vendor indicated that degradation of the nature observed would have resulted in an EDG experiencing a bearing related failure in an indeterminate period of operation, (6) the degraded condition may have existed for an extended time, and (7) the cause and extent of condition regarding the number of degraded components were not conclusively determined (Section 4OA3.1).

- TBD. The inspectors identified a URI involving the failure to follow a procedure to realign (reopen a manual valve) a boric acid tank flow path to the reactor coolant system (RCS) after boric acid was transferred to the tank from another boric acid tank. This resulted in the unavailability of a boric acid flow path to the RCS.

The finding was determined to have potential safety significance greater than very low significance because the function to provide highly concentrated boric acid to the refueling water storage tank (RWST) during a steam generator tube rupture event was lost (Section 4OA3.3).

- Green. The inspectors identified a non-cited violation of 10 CFR 50 Appendix B, Criterion XVI, for failure to promptly identify a degraded condition related to seat leakage of the Unit 1 residual heat removal (RHR) heat exchanger-to-RWST bypass valve. This identification failure resulted in the valve condition not being corrected for over three years.

  The degraded condition, and thus the corrective action finding, was of greater than minor significance because the condition had a credible impact on safety due to increased operator burden and its effects on a mitigating system (e.g., RHR, RCS level instruments) availability/reliability. The degraded condition was of very low safety significance because sufficient defense-in-depth existed to mitigate the condition primarily during reactor coolant system water level monitoring during mid-loop operation (Section 1R15).

- Green. The inspectors identified a non-cited violation of Technical Specification (TS) 6.8.1.a, for failure to follow an RHR pump performance surveillance procedure, which required a Unit 2 RHR heat exchanger outlet flow control valve to be closed prior to starting the RHR pump. The failure to close the valve resulted in a system water hammer.

  The finding was of greater than minor significance because it had a credible impact on safety in that had the water hammer been more severe, as a result of increased gas accumulation, system operability could have been affected. The finding was of very low safety significance because RHR system operability was not impacted by the water hammer. (Section 1R22).

- Green. The inspectors identified a non-cited violation of TS 6.8.1.a, for an inadequate abnormal operating procedure (AOP), used to respond to reactor coolant pump (RCP) malfunctions. The AOP had been revised, inappropriately reducing a minimum RCP seal water leakoff low flow requirement for one of the four Unit 1 RCPs.

  The procedure deficiency had a credible impact on safety because it would have allowed operation of the affected RCP in a condition that could have resulted in damage to the RCP seal and potentially resulting in a small break loss of coolant accident (LOCA). The licensee's risk analysis identified that small break LOCAs are significant contributors to the plant's core damage frequency. Because the affected RCP did not operate below the correct minimum flow, the finding was of very low safety significance (Section 4OA3.2).

B. <u>Licensee Identified Violations</u>

A violation of very low safety significance which was identified by the licensee has been reviewed by the inspectors. Corrective actions taken or planned by the licensee appear reasonable. This violation is listed Section 4OA7.

Report Details

Summary of Plant Status: Units 1 and 2 operated at or near 100 percent power for the entire inspection period.

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

1R04 Equipment Alignment

a. Inspection Scope

The inspectors conducted equipment alignment partial walkdowns to evaluate the operability of selected redundant trains or backup systems, listed below, with the other train or system inoperable or out-of-service. The walkdowns included a review of applicable operating procedures to determine correct system lineups and an inspection of critical components (e.g., power supplies, support systems) to identify any discrepancies that could affect operability of the redundant train or backup system.

- Emergency diesel generators (EDGs) 2A-A, 2B-B, and 1B-B during 6.9KV shutdown board relay testing that rendered 1A-A EDG inoperable
- EDGs 1A-A, 1B-B, and 2A-A and key safety equipment powered from these EDGs during extended maintenance on EDG 2B-B.
- Both trains of essential raw cooling water (ERCW) pumps and associated strainers and support systems [problem evaluation report (PER) 01-006474-000]

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors conducted tours of areas important to reactor safety, listed below, to evaluate conditions related to (1) control of transient combustibles and ignition sources; (2) the material condition, operational status, and operational lineup of fire protection systems, equipment and features; and (3) the fire barriers used to prevent fire damage or fire propagation. The inspectors referenced SPP-10.10, Control of Transient Combustibles, and prefire plans for the areas listed below, as appropriate.

- ERCW center bay, second level
- Unit 1 6.9 KV shutdown board room
- Unit 2 turbine building lower level
- Main control room
- Unit 2 turbine driven auxiliary feedwater pump room
- Centrifugal charging pump 2A-A room
- EDG building cable gallery room

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

a. Inspection Scope

The inspector reviewed licensee programs, tests, and inspection activities to provide assurance of the integrity and operability of the component cooling system (CCS), EDG jacket water heat exchangers and the ERCW system. This included a review of the below listed documents, discussions with system engineers, a review of intake pumping station underwater inspection video tapes, and field observations. The inspector reviewed documentation to confirm that the licensee had continued to meet commitments for Generic Letter 89-13, Service Water System Problems Affecting Safety Related Equipment. In addition, the inspector reviewed licensee actions associated with recent problems experienced with asiatic clams in raw water cooling systems at another licensee nuclear facility. This included the licensee's decision to scope the raw water chemical treatment system under the Maintenance Rule (MR) and establish specific performance criteria for system failures due to the presence of clams or mussels. Additionally, the inspector reviewed eddy current examination results to monitor for degradation of tubes in the EDG jacket water heat exchangers.

The inspector also reviewed documentation to confirm that ongoing frequent heat exchanger inspection/maintenance activities, test methodology, system performance monitoring, operational guidance, and system chemical treatments were consistent with accepted industry practices.

Procedures

- 0-MI-MIN-000-070.0, Cleanliness of Fluid Systems for Maintenance and Minor Modification Activities
- 0-MI-MRR-070-611.0, Component Cooling Heat Exchanger Maintenance
- Periodic Instruction, PI-757, Lower Containment Compartment Cooler Post Accident Mode Operability Test Unit 1 Train A
- 1-PI-SFT-070-001.0, Performance Testing of Component Cooling Heat Exchangers 1A1 and 1A2
- 1-PI-SFT-067-556A ERCW System Flow Balance Train A
- 1-PI-SFT-067-556B, ERCW System Flow Balance Train B
- Preventive Maintenance Instruction, PM 030330000 Intake Pumping Station Diver Inspection
- PM 041081000, Lower Containment Compartment Cooler Inspection
- PM 041481000, Containment Spray Heat Exchanger Inspection
- PM 030551000, Safety Injection Pump Oil Cooler Inspection
- PM 041431001, Component Cooling Heat Exchanger Inspection
- Technical Instruction, 0-TI-SXX-000-146.0, Program for Implementing Generic Letter 89-13

PERs

- 01-006936-000, Small amount of clam shells found in 2A charging pump oil cooler
- 01-007322-000, Presence of clams in condenser cooling screen wash pump strainers

Work Orders

- 00-006894-000, CCS heat exchanger 2A1 clam and MIC inspection
- 00-011268-000, CCS heat exchanger 2A1 clam and MIC inspection

Other Documents

- Sequoyah Nuclear Plant - Revised Program and Status Update Regarding NRC Generic Letter 89-13 - Service Water System Problems Affecting Safety-Related Equipment, September 22, 1995
- Diesel Generators 1AA and 2AA Coolers 1 and 2 Eddy Current Examination Report, January 1999
- TVAN Calculation MDQ0067-970004, ERCW Design Basis Multiflow Hydraulic Model

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed licensed operator requalification training activities in the plant simulator and the subsequent evaluators' discussions and feedback to the crew. The inspectors observed two simulator accident scenarios, one involving a large break loss of coolant accident with degraded core cooling and the other involving a loss of 480V shutdown board and loss of non-essential air. Both scenarios exercised the operators' ability to make timely and accurate emergency plan declarations. The inspectors referenced simulator exercise guides for these scenarios during the inspection. The inspectors reviewed simulator evaluations for previously-identified weaknesses and observed the following operating crew attributes: (1) clarity and formality of communication; (2) ability to take timely action in the safe direction; (3) prioritization, interpretation, and verification of alarms; (4) correct use and implementation of procedures, including the alarm response procedures; (5) timely control board operation and manipulation, including high-risk operator actions; (6) oversight and direction provided by the shift manager, including the ability to identify and implement appropriate technical specification (TS) actions such as reporting and emergency plan actions and notifications, and (7) the group dynamics involved in crew performance.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation

a. Inspection Scope

The inspectors sampled portions of selected structures, systems or components (SSCs), listed below, as a result of performance problems, to assess the effectiveness of the licensee's maintenance practices. The inspectors evaluated the licensee's MR implementation against Procedure SPP-6.6, Maintenance Rule Performance Indicator, Monitoring, Trending, and Reporting - 10 CFR 50.65; NUMARC 93-01, Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants; and Instruction 0-TI-SXX-000-004.0, same title as SPP-6.6. Reviews focused on: (1) MR scoping; (2) characterization of failed SSCs; (3) safety significance classifications; (4) 10 CFR 50.65 (a)(1) or (a)(2) classifications; and (5) the appropriateness of performance criteria for SSCs classified as (a)(2) or goals and corrective actions for SSCs classified as (a)(1).

SSC	Related Documents
Preferred inverter failure (System 250)	Work order (WO) 01-006079-000; PER 01-006156-000; PER 01-006080; 0-SO-250-4, 120V AC Preferred Power System.
Spreading room exhaust fan A-A discharge damper 0-FCO-31A-79 failed to close during testing	Work request (WR) C460481; July 19 maintenance shift log; PER 01-004934-000; 0-SI-SFT-031-144.B, Control Room Emergency Ventilation Test Train B; heating ventilating and air conditioning air flow diagram, 1,247W866-4
Annunciator scanners performance problems	PER 01-006231-000; PER 01-007301-000; WR C455061; WO 01-5468-001; DN ICS-84-SDF-03
480V board room 1B air handling unit found tripped	CDEF 1329; PER 01-007215-000; WO 01007042-000
Electric board room chiller AA temperature control valve stuck open	CDEF 1322; PER 01-005497-000; WO 01-005534-000
2-FCV-43-58 failed to close when given a close signal; 2-FCV-43-58A open/closed indication cross-wired	PER 01-006640-000; WO 01-006170-001; July 26 maintenance shift log entry; PER 01-006172-000

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors evaluated, as appropriate for the selected work activities: (1) the effectiveness of the risk assessments performed before maintenance activities were conducted; (2) the management of risk that, upon identification of an unforseen situation, necessary steps were taken to plan and control the resulting emergent work activities; and (3) that maintenance risk assessments and emergent work problems were adequately identified and resolved. The inspectors referenced Procedures SPP-7.1, Work Control Process, and Instruction 0-TI-DSM-000-007.1, Equipment to Plant Risk Matrix, during these inspection activities.

Work/Activity	Related Documents
Functional testing of reactor coolant pump (RCP) undervoltage and underfrequency relays	1(2)-SI-TFT-068-230.0, Functional Test of RCP's 1, 2, 3, and 4 Underfrequency Relays [C.1]; 1(2)-SI-TFT-068-228.0, Functional Test of RCP 1, 2, 3, and 4 Undervoltage Relays [C.1]
Preferred inverter failure (System 250)	PER 01-006156-000; WO 01-006079-000; AOP-P0.9, Loss of 120V AC Preferred Power
EDG 1A-A engine 1A1 power pack change-out following increasing trend of silver in the lubricating oil and discovery of failed 2B-B EDG power pack 11 wrist pin bearing	PER 01-007844-000
Schedule issues following mid-week emergent work-week train swap	PER 01-007861-000
Planned maintenance on motor driven AFW pump 2B, component cooling water heat exchanger 0B-1, and ERCW pumps L-B and M-B	PER 01-005627-000; control room operator log for June 19, 2001

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed selected technical operability evaluations (TOEs) and PERs, listed below, and related documents for issues affecting risk-significant mitigating systems to assess, as appropriate: (1) the technical adequacy of the evaluations; (2) whether continued system operability was warranted; (3) whether other existing degraded conditions were considered as compensating measures; (4) where compensatory measures were involved, whether the compensatory measures were in place, would work as intended, and were appropriately controlled; and (5) where continued operability was considered unjustified, the impact on TS limiting condition for operation (LCO) and the risk-significance in accordance with the SDP. The inspectors referenced Procedure SPP-10.6, Engineering Evaluations for Operability Determination, as needed, during the course of these inspection activities.

Operability Evaluation Inspected	Related Documents Reviewed
ERCW pump M-B overload annunciator	Caution order 0-67-0532A-W/W
2AS Turbine driven auxiliary feedwater pump (TDAFWP) vibration in alert status	PER 01-003219-000
Seat leakage of Unit 1 reactor cavity drain valve, 1-HCV-74-34	PER 01-002325-000; PER 00-008828-000; PER 00-001404-000; WO 98-010966-000; 0-SO-74-1, Residual Heat Removal System, Rev.29
T-drains for centrifugal charging pump 2B cooler motor installed incorrectly	PER 01-006369-000; SQN-DC-V-21.0, Sequoyah Nuclear Plant - Environmental Design Criteria
Malfunctions of EDGs 1B1 and 2A2 EDG air start system pressure control valves cause uncontrolled blowdown of starting air receivers	PER 01-006924-000; PER 01-007184-000.

b. Findings

A finding of very low safety significance (Green) was identified by the inspectors involving the identification and correction of a degraded condition of the Unit 1 residual heat removal (RHR) heat exchanger-to-refueling water storage tank (RWST) bypass valve. This finding was also a non-cited violation of 10 CFR 50 Appendix B, Criterion XVI (Corrective Action).

On October 5, 1998 during a Unit 1 refueling outage (RFO), the licensee identified that manually-operated and normally closed valve 1-HCV-74-34 was difficult to operate and leaked past its seat. The valve, which is safety related, provides isolation between the RHR system and the RWST and is used during RFOs to drain the reactor cavity to the RWST. Although a PER was not initiated, the licensee did initiate a WO, 98-010966-000, for the valve's repair. The WO, however, did not provide any information quantifying the valve's leak rate, did not provide a complete evaluation of the impact of the leakage on plant operations, nor did it provide a schedule for when the work was needed to be completed. Approximately 11 months after initial identification, on August 27, 1999, the licensee scheduled the valve's repair during the Fall 2001 refueling outage when an RWST outage was scheduled. The RWST must be drained to repair the valve. The valve was not repaired during the Spring 2000 refueling outage because an RWST outage had not been scheduled.

On September 30, 2000, while operating the RHR system during a forced shutdown, the licensee discovered that the valve's seat leakage caused a RWST high water level condition. The licensee tightened the valve in the close direction and estimated that the leak rate was reduced to about 0.3 gpm. PER 00-008828-000 was initiated which included corrective actions to: (1) ensure a WO was in place to repair the valve, and (2) revise the RHR operating procedure to provide compensatory actions for isolating reactor coolant leakage through the valve. The management review committee (MRC) also directed that a caution order be placed on the valve when placing RHR in service. This restriction was directed because operation with the B train through reactor coolant system (RCS) cold legs one and four would cause RCS level perturbations since the level instruments were configured to those injection loops. Approximately five months after the September 30 event, on February 27, 2001, the MRC's direction was completed, with the caution order being placed on the RHR crosstie valves to alert the operators that RHR operation was limited to the A train due to the inventory problems created by the leakage with either RHR crosstie valve open.

On March 3, 2001, another PER, 01-002325-000, was initiated by the Operations Department, independent of the September 2000 PER, because the impact of the valve's leakage on plant operations had not yet been fully evaluated. These impacts included: (1) dilution of the RWST when operating RHR, (2) inventory control problems when operating RHR, (3) effects on the RHR system during mid-loop operations and associated impact on RCS level instruments, and (4) source term effects of RHR operation during containment sump recirculation where the radioactive sump inventory would leak directly to the RWST. The corrective action for the PER focused on the source term impacts of potential leakage to the environment via the RWST vent line.

The inspectors reviewed the multiple plant impacts of this degraded but operable condition and determined that the most risk significant plant effect was the complexity added to RHR operation and the potential negative impact on RCS level instruments while in mid-loop. RWST dilution effects and increased operator burden for RCS makeup were considered to be of minor safety significance. In addition, the source term effects while operating in containment recirculation were also of minor significance based on calculations previously performed by the licensee that demonstrated that the leak rate combined with the expected behavior of fission products during a design basis loss of coolant accident had a minimal impact on 10 CFR 50 Appendix A (GDC-19) and

Part 100 release limits. The inspectors reviewed the calculations and determined that the licensee's position was justified.

The licensee's corrective action program procedure, SPP-3.1, Corrective Action Program, Rev. 0 that was in effect at the time of initial discovery of the valve leakage, required that SSCs that are degraded be entered into the corrective action program by initiation of a level C PER. The licensee did not initiate a level C PER in October 1998, based on the degraded performance of the valve, and thus the leaking valve was not evaluated for prompt repair. SPP-3.1 also required, in Appendix G, that degraded conditions that are not corrected within one cycle of operation be justified through an evaluation addressing, in part, the safety significance and impact of any required compensatory measures on plant operations. Due to not initiating a PER, the licensee did not recognize that a justification was required for not repairing the valve during the Spring 2000 RFO. Although, at the time of this inspection, the degraded condition continued to exist, the inspectors confirmed that the WO to repair the valve was included in the scope of the RWST outage scheduled for the Fall 2001 RFO. The failure to identify the leaking valve as being a degraded component resulted in a PER not being generated, and ultimately the degraded condition remaining uncorrected for over three years.

The inspectors determined that the leaking valve complicated operator response to the mid-loop evolution that is one of the more risk significant plant configurations during plant shutdown conditions. Although the risk impact of limiting RHR operation during mid-loop was not quantified, the inspectors determined that the condition had a credible impact on safety due to increased operator burden and its effects on a mitigating system (e.g., RHR, RCS level instruments) availability/reliability. The leaking valve was of very low safety significance because sufficient defense-in-depth existed to mitigate the degraded condition primarily during RCS water level monitoring during mid-loop operation. Because the degradation of the bypass valve was determined to be of very low safety significance, the inspectors determined that the corrective action finding was also of very low safety significance (Green).

Criterion XVI of 10 CFR 50 Appendix B requires that conditions adverse to quality be promptly identified. The inspectors determined that the licensee's identification of the leaking valve as being a degraded component was not prompt, resulting in the subsequent corrective action also being untimely. However, because the violation was of very low safety significance and was entered in the licensee's corrective action program, the violation is being treated as a non-cited violation (NCV), consistent with Section VI.A.1 of the NRC Enforcement Policy, and is identified as NCV 50-327/01-03-01: Failure to Promptly Identify and Subsequently Correct Valve Seat Leakage. This deficiency is in the licensee's corrective action program as PER 01-002325-000.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed Procedure SPP-6.3, Pre/Post Maintenance Testing (PMT) which governs the licensee's PMT process, and WOs and/or test activities, as appropriate, for selected risk-significant mitigating systems to assess whether: (1) the effect of testing on the plant had been adequately addressed by control room and/or engineering personnel; (2) testing was adequate for the maintenance performed; (3) acceptance criteria were clear and adequately demonstrated operational readiness consistent with design and licensing basis documents, (4) test instrumentation had current calibrations, range and accuracy consistent with the application, (5) tests were performed as written with applicable prerequisites satisfied; (6) jumpers installed or leads lifted were properly controlled; (7) test equipment was removed following testing; and (8) equipment was returned to the status required to perform its safety function.

Post Maintenance Test Inspected	Related Documents Reviewed
Spreading room exhaust fan A-A discharge damper 0-FCO-31A-79 failed to close as required during testing.	WR C460481; July 19 maintenance shift log; PER 01-004934-000; 0-SI-SFT-031-144.B, Control Room Emergency Ventilation Test Train B; heating ventilating and air conditioning air flow diagram 1,2-47W866-4
No. 1 120 V AC preferred power inverter failure	PER 01-006080; WR C416847; WO 01-006079-000; AOP-P.09, Loss of 120V AC Preferred Power
EDG 1A2 air compressor temporarily rendered unavailable due to malfunctioning pressure switch failing to stop compressor and subsequent lifting of safety valve 82-528	Maintenance shift log entry on July 23; WO-01-006438-000; control room log entries on July 27 and July 28; WO 01-006656-000
2A-S TDAFWP testing following replacement during U2C10 March 2000 refueling outage	PER 01-003219-000; WO 01-003485-000
Unit 2 pressurizer heater backup group B	0-SI-OPS-068-297.0, Pressurizer Heater Capacity; WO 01-001504-000; WO 01-002164-000
Position indication problem with containment vacuum relief valve 2-FCV-30-46	WO 01-007246-000; MI-10.37, Inspection and Maintenance of NAMCO Limit Switches; 2-SXV-000-201.0, Full Stroking of Category "A" and "B" Valves During Operation; 0-SI-SXV-030-266.0, ASME Section XI Valve Testing

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed surveillance tests and/or reviewed test data of selected risk-significant SSCs conducted using the surveillance instructions (SI), listed below, to assess, as appropriate, whether the SSCs met TS, the UFSAR, and licensee procedure requirements, and to determine if the testing effectively demonstrated that the SSCs were operationally ready and capable of performing their intended safety functions.

Surveillance/Equipment Test Inspected	Related Documents Reviewed
EDG 2B-B test	2-SI-OPS-082-007.B, Electrical Power System Diesel Generator 2B-B; PER 01-006433-000
Relay functional testing of 6.9 KV shutdown board 1A-A	1-MI-TFT-202-016.A, Relay Functional Test for 6.9 KV Shutdown Board 1A-A, Alternate Breaker 1716; WO 01-001058-000, Alternate Feeder Breaker 1716 SDBD 1A-A Relay Functional Test; WO 01-01052-000, Relay Functional for 6.9 KV Shutdown Bd 1A-A Alternate Feeder Breaker 1712 on Unit Board 1A
Functional test of RCP undervoltage and underfrequency relays	1-SI-TFT-068-230.0, Functional Test of RCP's 1, 2, 3, and 4 Underfrequency Relays [C.1]; 1-SI-TFT-068-228.0, Functional Test of RCP 1, 2, 3, and 4 Undervoltage Relays [C.1]; 2-SI-TFT-068-230.0, Functional Test of RCP's 1, 2, 3, and 4 Underfrequency Relays [C.1]; 2-SI-TFT-068-228.0, Functional Test of RCP 1, 2, 3, and 4 Undervoltage Relays [C.1]
2A-S TDAFWP surveillance test modification following identification of vibration in the alert range	PER 01-003219-000; WO 01-003485-000
RHR pump 2B-B performance test	2-SI-SXP-074-201.B, Residual Heat Removal Pump 2B-B Performance Test, Rev. 6; PER 01-004196-000; PER 00-008645-000; control log entries for April 27, 2001

Diesel generator operability verification	0-SI-OPS-082-007.0, Diesel Generator Operability Verification

b. Findings

A finding of very low safety significance (Green) was identified by the inspectors for failure to follow an RHR pump performance surveillance procedure, which required a Unit 2 RHR heat exchanger outlet flow control valve to be closed prior to starting the RHR pump. The failure to close the valve resulted in a system water hammer. The finding was also a non-cited violation of TS 6.8.1.a, (Procedures and Programs).

On April 27, 2001 while operators were performing a routine operability test for the 2B-B RHR pump, the local pump discharge flow indicator unexpectedly pegged high and metal clanging was heard by workers in the pump area. In addition, indications of a water hammer (e.g., dust particles were noted in the pump room) were observed. The test was being performed in accordance with SI 2-SI-SXP-074-201.B, Residual Heat Removal Pump 2B-B Performance Test, Rev. 6. Step 6.1[4] of the test required the operator to close valve 2-FCV-074-28 prior to starting pump. Closure of this valve, which is the RHR heat exchanger 2B outlet flow control valve, isolates the pump discharge and places the system flow path through the minimum flow line back to the pump suction while the pump is running. The licensee performed a system walkdown to check for water hammer damage (e.g., chipped paint, damaged piping insulation, mispositioned pipe hangers, or broken welds) and found no problems. The licensee also determined that the clanging noise heard was attributable to the RHR pump discharge check valve operation. The licensee further determined that the operator who had conducted the test failed to close the valve as required by step 6.1[4] and cited the apparent causes of the incident to be operator in-attention, failure to obtain a peer check, and failure to recognize the importance of closing the valve. The licensee entered this self-revealing event into their corrective action program.

The inspectors discussed the incident with engineering and operations personnel, reviewed related operator log entries and the associated performance test to confirm the circumstances associated with the incident. In addition, the inspectors walked down portions of the RHR piping and no damage to system components was noted. The inspectors also reviewed the licensee’s corrective action plan and noted that the reason valve 2-FCV-074-28 is closed during the test is due to the buildup of gas in the RHR discharge piping. The normal position of the valve with RHR in standby is open. The valve is closed to prevent a system water hammer when the pump is started for routine testing. The inspectors confirmed that the valve automatically opens if a safety injection signal is initiated.

The inspectors evaluated the safety significance of the operator’s failure to close valve 2-FCV-074-28. Although a water hammer occurred, based on the licensee’s walkdown results, no system damage was evident. The incident did, however, have a credible impact on safety because depending on the degree of gas buildup in the RHR piping, more significant consequences due to water hammer could have resulted, possibly affecting the operability of the RHR system. The finding was of very low safety significance (Green) because system operability was not impacted.

TS 6.8.1.a, requires, in part, that written procedures be implemented, covering the activities referenced in the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Rev. 2, February 1978. Contrary to these requirements, the operator involved failed to perform Step 6.1[4] of SI 2-SI-SXP-074-201.B which is a procedure included within these requirements. However, because the violation was of very low safety significance and was entered in the licensee's corrective action program, the violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy, and is identified as NCV 50-328/01-03-02, Failure to Follow RHR Performance Test Procedure. This deficiency is in the licensee's corrective action program as PER 01-004196-000.

1EP6 Drill, Exercise, and Actual Events

a. Inspection Scope

The inspectors observed the licensee's red team perform the annual emergency exercise. The inspectors focused on the licensee's ability to make accurate and timely emergency action level classifications and subsequent notifications to the state government. The inspectors reviewed the drill scenario and observed drill performance in the control room simulator and the technical support center. The inspectors also attended the exercise critique that was presented to plant management.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY
Cornerstone: Occupational Radiation Safety

2OS2 As Low As Reasonably Achievable (ALARA) Planning and Controls

a. Inspection Scope

The inspectors evaluated the plant collective exposure history, current exposure dose trends, and the calendar year 2001 annual site dose goal to determine whether the licensee was implementing ALARA practices as required by 10 CFR 20.1101(b) and Procedure RCI-10 ALARA Planning Report Criteria. The inspectors also evaluated source term reduction efforts and the incorporation of ALARA into licensee Radiation work permits. The evaluation included ALARA planning, dose goals and estimates, daily dose results, job dose trends and problem identification and resolution, and ALARA Committee meeting minutes. The Unit 2 Cycle 10 ALARA outage report was evaluated for outage dose performance, dose rate trends, shutdown chemistry crud burst and clean-up, temporary shielding and ALARA post-job review for lessons learned. Self-Assessment reports technical findings from, SQN-RP-01-001, SQN-RP-01-005 were evaluated for corrective actions.

The inspectors toured the dry active waste building, auxiliary building and refueling floor, to evaluate housekeeping, outage preparations and radioactive material storage. New fuel shipment receipt and offload was also observed. The inspectors attended planning meetings for the Unit 1 steam generator replacement outage.

The following ALARA planning reports and procedure revisions for the U1C11 RFO were evaluated for lessons learned and dose goal planning:

- 2001-31 Unit 1 Steam Generator Replacement N-1 activities
- 2001-34 Split Pin Replacement
- RCI-22 Contamination Control Revision 8, dated 09/14/01

b. Findings

No findings of significance were identified.

3. SAFEGUARDS
Cornerstone: Physical Protection

3PP1 Access Authorization

a. Inspection Scope

The inspector evaluated licensee procedures, fitness for duty (FFD) reports, and licensee audits. Additionally, the inspector interviewed five representatives concerning their understanding of the behavior observation portion of the personnel screening and FFD program. In interviewing these personnel, the inspector evaluated the effectiveness of their training and abilities to recognize aberrant behavioral traits, physiological indications of narcotic and alcohol use, and work call-out reporting procedures. Licensee compliance was evaluated against requirements in the Plant Physical Security Plan and associated procedures, and 10 CFR Part 26, Fitness For Duty Programs.

- SPP - 1.2, Fitness For Duty
- SPP - 1.3, Plant Access and Security
- Nuclear Security Self-Assessment, Assessment NO.: SA-NSS-00-002, Plant Access, Fitness For Duty and Continual Behavior Observation

b. Findings

No findings of significance were identified.

3PP2 Access Control

a. Inspection Scope

The inspector observed access control activities on August 27, 28 and 29 and search/access control equipment testing was observed on August 29. In observing the access control activities, the inspector assessed whether officers could detect contraband prior to it being introduced into the protected area. The protective barriers for the final access control facility were inspected to ensure compliance with protection standards in the physical security plan. Additionally, the inspector assessed whether the officers were conducting access control equipment testing in accordance with regulatory requirements through observation, review of procedures, and log entries. Preventative and post maintenance procedures were evaluated and observed as performed. Lock, combination, and key control procedures were evaluated, as well as were aspects of the site access authorization program. Licensee compliance was evaluated against requirements in the Plant Physical Security Plan and associated procedures, and 10 CFR Part 73.55, Requirements for Physical Protection of Licensed Activities in Nuclear Power Reactors Against Radiological Sabotage, and Part 73.56, Personnel Access Authorization Requirements for Nuclear Power Plants.

- Physical Security Plan
- Safeguards event logs for the proceeding 12 months, 2000-2001
- Sequoyah self assessment, Nuclear Security Self-Assessment, Assessment NO.: SA-NSS-00-002, Plant Access, Fitness For Duty and Continual Behavior Observation
- O-PI-SQS-000-646.W, Metal Detector Functional Test
- O-PI-SQS-000-643.W, X-Ray Equipment Functional Test
- O-PI-SQS-000-647.W, Explosive Detection Functional Test

b. Findings

No findings of significance were identified.

OTHER ACTIVITIES

4OA1 Performance Indicator Verification

Licensee records were reviewed to determine whether the submitted Performance Indicator (PI statistics were calculated in accordance with the guidance contained in Nuclear Energy Institute 99-02, Regulatory Assessment Performance Indicator Guideline. Licensee Business Practice BP-243, Performance Indicator Information to NRC, was also referenced. The licensee's corrective action program records were reviewed to determine if any problems with the collection of PI data had occurred and if resolution was satisfactory. When possible, plant activities that generated the PI data input were observed.

.1 Safety System Functional Failures

a. Inspection Scope

The inspectors reviewed licensee event reports (LERs), MR records, and maintenance WOs for the period from July 2000 through June 2001 to verify the accuracy and completeness of the PI data for safety system functional failures. In addition, the inspectors reviewed the licensee's corrective action program to determine if any problems with the collection of PI data had occurred and if resolution was satisfactory. Specific LERs reviewed included:

- LER 50-327/2000-004, Reactor Trip on Low-Low Steam Generator Level as a Result of the Loss of a Main Feedwater Pump
- LER 50-328/2000-003, Missed SI - Failure to Perform Containment Sump Level Instrument Channel Functional Tests (CFTs) on Containment Sump Level Channels
- LER 50-328/2000-004, Reactor Trip Resulting from a Fault in a Main Transformer Caused by a Failed Bushing

b. Findings

No findings of significance were identified.

.2 RCS Specific Activity

a. Inspection Scope

The inspectors reviewed daily RCS chemistry sample analysis results for maximum dose equivalent iodine (DEI)-131 for the period from July 2000 through June 2001 to verify that the percent of TS limit was the same or lower than the maximum value reported by the licensee for the applicable month. The inspectors also observed a chemistry technician take and analyze a routine RCS grab sample to verify that the sample and analysis were performed according to the guidance in Instruction 0-TI-CEM-000-016.3, Sampling Methods-Primary Systems, and TI-12, Radiological Analytical Methods. The analyzed value of DEI from such RCS samples provided the data for the PI involving RCS specific activity. In addition, the inspectors reviewed PERs 01-006584-000, 01-006626-000, and 01-007219-000, related to the sampling or the analysis of the RCS sample, or the reporting of the PI.

b. Findings

No findings of significance were identified.

.3 Fitness-For-Duty/Personnel Reliability Program Performance, Personnel Screening Program Performance and Protected Area Security Equipment Performance Index

a. Inspection Scope

The inspector evaluated licensee programs for gathering and submitting data for the above listed PIs. The evaluation included licensee's tracking and trending reports and security event reports for the PI data submitted from the first quarter to the third quarter of 2001.

b. Findings

No findings of significance were identified.

4OA3 Event Follow-up

.1 Failure to Implement 2B-B EDG Maintenance Procedure

a. Inspection Scope

Between August 27 and September 1, the licensee identified degraded engine components in the 2B-B and 1A-A EDGs. The inspectors reviewed the licensee's subsequent response to the damaged components. The inspectors also met with engineering and maintenance personnel and examined licensee records and industry information to determine whether licensee performance issues were involved.

b. Findings

The inspectors identified an unresolved item involving failure to properly implement an EDG maintenance procedure. The licensee identified severe degradation of a piston wrist pin and bearing insert in the 2B-B EDG. Following an inspector request for maintenance documents, the licensee identified a failure to properly implement a maintenance procedure completed five months earlier. Maintenance personnel had incorrectly marked an out-of-specification condition as acceptable, supervisory reviews had failed to detect the error, and the 2B-B EDG had been returned to service without evaluation or investigation of the condition. By the time the error was detected, severe component degradation had occurred. Pending further NRC review of the impact of the degraded engine components on EDG function and the subsequent determination of the finding's safety-significance, a URI was identified.

Chronology

On or about March 14, 2001, during performance of step 6.14 of Maintenance Procedure 2-PI-MDG-082-002.B, Two Year Preventive Maintenance of Diesel Engine Set 2B-B, Revision 4, maintenance personnel measured and recorded a 2B2 engine cylinder 11 piston-to-head clearance of 0.069 inches. This value exceeded the maximum clearance acceptance criteria of 0.068 inches. Contrary to procedure guidance, the condition was incorrectly marked as acceptable, supervisory reviews failed to detect the error, and the 2B-B EDG was returned to service without evaluation or investigation of the condition.

On June 5, 2001, an oil sample analysis from the 2B-B EDG number 2 engine (2B2) revealed a silver concentration of 1.1 parts per million (ppm). The engine piston wrist pin carrier bearings (insert bearings) and turbocharger bearings contain a silver substrate beneath a lead-tin overlay. Increasing silver concentration in the engine oil indicates a potential bearing degradation problem. According to the vendor manual, a silver concentration from 0 to 1 ppm is considered “NORMAL - No Action Required,” silver from 1 to 2 ppm is considered “BORDERLINE - Take Extra Oil Samples,” and silver above 2 ppm is deemed ”HIGH - Correct Condition.” The licensee increased oil analysis frequency in response to the borderline condition.

Follow-up oil samples obtained on July 3 and July 31 revealed 1.0 and 1.3 ppm silver, respectively, confirming that one or more 2B2 engine piston carrier bearings and/or turbocharger bearings had degraded to a borderline condition from a previous condition, in all the EDGs, in which silver was consistently non-detectable.

On August 7 an oil sample from 1A-A EDG engine 1A1 revealed an increase in silver from non-detectable to 0.7 ppm. On August 23, PER 01-007598-000 was initiated to document the results, evaluate the sample technique, and review the analysis method, noting that the analysis results appeared to be erroneous. The inspectors discussed this with the licensee and determined that there had been problems with faulty analyses in the past. The analytical laboratory involved is operated by the licensee. The inspectors determined that the licensee was neither aware nor able to obtain from their laboratory the analytical method’s precision or minimum detection threshold for silver in engine oil.

On or about August 20, the inspectors discussed with the licensee an EDG failure that had occurred in April 2001 at another nuclear facility and the fact that the failure had been preceded by an increasing silver trend. General Motors, Electro-motive Division (EMD) diesel engines at that nuclear facility are similar to the licensee’s EDGs but with 20 instead of 16 cylinders per engine. The other nuclear facility had submitted a LER on June 22, 2001, documenting excessive wear on the piston wrist pins and bearing inserts in three cylinders of the number three EDG. All 20 power assemblies were replaced and an evaluation concluded that the EDG had been inoperable for a period exceeding the TS action statement. The LER noted that the 2 ppm action level established by the EDG vendor was based upon expected even wear patterns in all cylinders. Similar to the licensee, the other nuclear facility also observed increasing silver in a second (the number 1) EDG.

On August 27, the licensee determined the as-found number 11 cylinder piston-to-head clearances in the 2B2 engine to be unacceptable at 0.070 and 0.071 inches. Power assembly number five also failed the clearance criteria. On August 28, upon examination, the number 11 piston wrist pin and carrier bearing insert were found to be severely degraded characterized by extensive loss of bearing material along with its associated lubricating channels, heavy scoring and burning of the wrist pin, and bluing of portions of the wrist pin and carrier indicating abnormally high metal temperatures. Visual inspection of number five piston wrist pin and carrier bearing insert showed no signs of abnormal wear. Both the number 11 and number five power assemblies were replaced. No further action was taken with regard to the remaining 14 power assemblies.

Following an inspector request for copies of past maintenance documentation, the licensee initiated PER 01-007771-000 identifying the March 14, 2001 failure to properly implement Maintenance Procedure 2-PI-MDG-082-002.B. A piston-to-head clearance recorded for cylinder 11 in the 2B2 engine had, at 0.069 inches, exceeded the procedure-specified acceptance criteria of 0.068 inches. Maintenance personnel had incorrectly recorded the out-of-specification condition as acceptable, supervisory reviews had failed to detect the error, and the 2B-B EDG was returned to service without evaluation or investigation of the condition.

On August 28, the licensee, having observed the 2B2 EDG component degradation and recognizing a potential common cause failure potential to the remaining EDGs, conducted ambient starts of the 1A-A, 2A-A, and 1B-B EDGs in accordance with TS 3.8.1.1 Action b., loaded each engine for a brief period and sampled the engine oil from each for silver. The 1A1 engine oil sample confirmed an elevated silver concentration of 0.8 ppm. The other EDG engines showed no detectable silver.

Following restoration of the 2B-B EDG, the 1A1 engine was examined. Piston-to-head clearance measurements all fell within acceptance criteria and, as with the 2B2 engine, an in-engine examination of piston wrist pins by touch and by using a flexible neck camera did not reveal abnormal conditions. The power assemblies were removed for work bench inspection. On September 1, the number 1 piston wrist pin and carrier bearing insert were discovered in a severely degraded state characterized by extensive loss of bearing material, loss of the associated oil channels, scoring and burning of the wrist pin. This power assembly, however, lacked the bluing of the portions of the wrist pin and carrier observed in the 2B2 engine.

Risk & Regulatory Perspectives

The inspectors determined the March 14, 2001 failure to properly implement maintenance procedure, 2-PI-MDG-082-002.B, to have credibly affected the function of the 2B-B EDG. The finding was determined to have potential safety significance greater than very low significance because (1) of the high safety importance of EDGs, (2) the maintenance error was not detected until severe component degradation had already occurred, (3) a second EDG (1A-A) was similarly and concurrently impacted for reasons not yet determined, (4) industry operating experience and the diesel engine vendor indicated that degradation of the nature observed would have resulted in an EDG experiencing a bearing related failure in an indeterminate period of operation, (5) the degraded condition may have existed for an extended time, and (6) the cause and extent of condition regarding the number of degraded components were not conclusively determined.

TS 6.8.1.a, requires, in part, that written procedures be implemented, covering the activities recommended in Appendix A of Regulatory Guide 1.33, Rev. 2. Paragraph 9 of Appendix A, Procedures for Performing Maintenance, recommends, in part, that maintenance that can affect the performance of safety-related equipment be properly performed in accordance with written procedures appropriate to the circumstances. The acceptance criteria in step 6.14 of maintenance procedure 2-PI-MDG-082-002.B, Two Year Preventive Maintenance of Diesel Engine Set 2B-B, Revision 4, specified that piston-to-head clearance not exceed 0.068 inches. Contrary to the above, on or about March 14, 2001, when the measured 2B2 engine cylinder 11 piston-to-head clearance, at 0.069 inches, exceeded the acceptance criteria, the licensee incorrectly determined the condition to be acceptable, failed to detect the error during supervisory reviews, and returned the 2B-B EDG to service without further evaluation or investigation of the condition. Pending further NRC review of the impact of the degraded engine components on EDG function and the subsequent determination of the finding's safety-significance, the issue is identified as URI 50-327, 328/01-03-03, Failure to Implement 2B-B EDG Maintenance Procedure.

.2 Deficient Abnormal Operating Procedure for Reactor Coolant Pump Malfunctions

a. Inspection Scope

On July 22, the Unit 1 #4 RCP number 1 seal water leakoff temperature increased from its normal operating value of about 155 degrees F to the alarm set point of 179 degrees F and stabilized. Concurrently, the number 1 seal leakoff flow rate had decreased below its normal operating value of about 2.0 to 3.0 gpm to about 1.6. gpm. RCP seal leakoff temperature and flow are direct indications of possible RCP seal damage. The inspectors, while performing routine plant status review, discussed with operations and engineering personnel the validity of an operating parameter for low seal water flow contained in abnormal operating procedure (AOP) R.04, Reactor Coolant Pump Malfunctions, Revisions 14 and 15. In addition, the inspectors reviewed historical and operating data for the #4 RCP number 1 seal water flow and temperature. Operating logs, technical information related to low seal water flow provided by the vendor, and related information in the Updated Final Safety Analysis Report were also reviewed.

b. Findings

A finding of very low safety significance (Green) was identified by the inspectors for an inadequate AOP which is used to respond to RCP malfunctions. This finding was also a non-cited violation of TS 6.8.1.a (Procedures and Programs).

Procedure AOP-R.04, Rev.15 which was in effect in July 2001, required that Unit 1 be shutdown in a controlled manner using normal operating procedures if the #1 seal leakoff flow decreased below 0.6 gpm for RCP #4 and 0.8 gpm for RCPs 1, 2 and 3. During plant status review, the inspectors discussed with the licensee the basis for the difference in the low seal water flow setpoints between the RCPs (i.e., 0.6 versus 0.8 gpm). The inspectors questioned the difference primarily because the #4 RCP had been replaced in October 2000 due to a high vibration condition and the inspectors wanted to ensure that the 0.6 gpm value was valid. The licensee stated that the flow rate differences was justified by a letter provided by the vendor.

On July 25, the licensee determined that Rev. 14 to AOP-R.04 which was approved on February 18, 2000, was not supported by the vendor letter (Rev. 14 was the revision that changed the value from 0.8 to 0.6 gpm for the Unit 1 #4 RCP only). In fact, a letter dated May 23, 1997 from Westinghouse to TVA, entitled, Reactor Coolant Pump Operation with Low No.1 Seal Leak Rate, stated that a seal leaking with a 0.8 gpm leak rate was not operating as designed and that running a RCP at leak rates below 0.8 gpm under normal pressure conditions presented a possibility that a seal failure could occur. The inspectors reviewed the letter and determined that it did not support the procedure change. On July 25, the licensee revised AOP-R.04 to require the unit be shutdown if seal water flow decreased to 0.8 gpm for the #4 RCP.

The inspectors evaluated the safety significance of the deficient procedure. The inspectors reviewed historical operating data to confirm that number 1 seal water leakoff flow for the Unit 1 #4 RCP had not decreased below 0.8 gpm since Rev. 14 of AOP was approved. The lowest value that was recorded was about 1.0 gpm. The procedure deficiency had a credible impact on safety because it would have allowed operation of the #4 RCP in a condition that could have resulted in damage to the RCP number 1 seal potentially resulting in a small break loss of coolant accident (LOCA). The licensee's risk analysis identified that small break LOCAs are significant contributors to the plant's core damage frequency. Because operation below 0.8 gpm did not occur, the issue was determined to be of very low safety significance (Green).

TS 6.8.1.a, requires that written procedures be established and maintained, covering the activities referenced in applicable procedures (Section 5 for procedures for abnormal, offnormal, or alarm conditions) recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Contrary to this requirement, AOP-R.04, Reactor Coolant Pump Malfunctions, Revisions 14 and 15, contained a nonconservative value for RCP number 1 seal water leakoff low flow. Specifically, the low seal water flow value was 0.6 gpm for the #4 RCP versus 0.8 gpm. Once the licensee discovered the procedure deficiency, the procedure was revised to correct the condition. However, because the violation was of very low safety significance and was entered in the licensee's corrective action program, the violation is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 50-327, 328/01-03-04, Failure to Adequately Maintain Abnormal Operating Procedure for RCP Malfunctions. This deficiency is in the licensee's corrective action program as PER 01-006639-000

.3 Failure to Realign the B Boric Acid Tank Flow Path to the Reactor Coolant System

a. Inspection Scope

On August 8, during a routine automatic RCS makeup to the volume control tank, operators observed that the makeup automatically stopped. Annunciation was received that indicated a deviation between boric acid and primary water flows. Operators then attempted a manual makeup but no boric acid flow was observed. Shortly afterwards, a valve lineup check was performed which identified filter bypass valve 2-VLV-62-1055B to be closed when it should have been open. Having the valve closed isolated the boric acid flow from boric acid tank (BAT) B to the RCS (BAT B is the normal flow path for Unit 2). A minor dilution event occurred during the event resulting a change in reactor power of about 1 megawatt thermal. The inspectors reviewed circumstances related to the mispositioning of the bypass valve which provides a flow path for boric acid injection from BAT B to the RCS when the system filter is out of service. The inspectors discussed this self-revealing event with operators and their management. In addition, the inspectors confirmed the plant's response to the event and equipment availability through a review of plant records such as control room logs and related corrective action documents.

b. Findings

The inspectors identified an apparent violation of TS 6.8.1.a, for failure to follow procedure for placing BAT B in service using BAT pump 2B-B. Manual filter bypass valve was not reopened, resulting in the unavailability of the boric acid flow path. This failure had potential safety significance because the function to provide highly concentrated boric acid to refill the RWST was lost for mitigation of steam generator tube rupture (SGTR) events. Pending determination of the finding's safety significance, a URI was identified.

The licensee's investigation determined that filter bypass valve 2-VLV-62-1055B had also previously had been closed on August 5 to transfer boric acid from BAT C to BAT B. When the system was realigned to its normal configuration operators failed to reopen the valve. The operators made an incorrect assumption that the valve did not need to be reopened. The operators assumed that the downstream system filter was in service when it was not. The filter was out of service due to a long standing problem with filter clogging and therefore the system bypass valve was required to be open. The procedure in use for both evolutions was 0-SO-62.10, Boric Acid Batch, Transfer, and Storage System, Rev.12. The valve was closed on August 5 at Step 8.3.2 [d]. The operators failed to reopen the valve at Step 5.1.2 [5][a].

The inspectors evaluated the safety significance of the issue and determined that failure to reopen the valve had a credible impact on safety because it rendered BAT B unavailable for anticipated transient without scram (ATWS) and SGTR mitigation. During this time, however, for ATWS mitigation, highly concentrated boric acid was available from the RWST through the high pressure charging pumps. The inspectors verified that both charging pumps were available and that the RWST was properly borated at the required TS level. The issue related to ATWS mitigation was therefore of very low safety significance. The finding was determined to have potential safety significance greater than very low significance because, for SGTR events, the function to provide highly concentrated boric acid to refill the RWST was lost.

TS 6.8.1.a, requires that written procedures shall be established, implemented and maintained covering the activities referenced in applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Contrary to this requirement, Step 5.1.2[5][a] of 0-SO-62-10 was not performed as required to realign BAT B flow path to the RCS after boric acid was transferred from BAT C to BAT B. Pending determination of the finding's safety significance, the issue is identified as URI 50-328/01-03-05, Failure to Realign Boric Acid Tank Flow Path to the RCS.

4OA6 Management Meetings

The inspectors presented the inspection results to Mr. Dennis Koehl, Plant Manager, and other members of licensee management on September 27, 2001. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

40A7 Licensee Identified Violations

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

NCV Tracking Number	Requirement Licensee Failed to Meet
NCV 50-328/01-03-06	TS 6.8.1.a, requires that written procedures shall be implemented covering the activities recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Contrary to this requirement, on July 26, 2001, sample valve 2-SMV-43-715 was not closed when completing step 6.3.2 [4] of 0-TI CEM-000-016.3, Sampling Methods - Primary Systems, Rev. 49. The issue is in the licensee's corrective action program as PER 01-006644-000 (Green).

PARTIAL LIST OF PERSONS CONTACTED

Licensee

T. Carson, Maintenance Manager
R. Drake, Maintenance and Modifications Manager
E. Freeman, Operations Manager
J. Gates, Site Support Manager
C. Kent, Radcon/Chemistry Manager
D. Koehl, Plant Manager
M. Lorek, Assistant Plant Manager
D. Lundy, Site Engineering Manager
R. Purcell, Site Vice President
P. Salas, Licensing and Industry Affairs Manager
K. Stephens, Security Manager
J. Valente, Engineering & Support Services Manager

NRC

R. Bernhard, Region II Senior Reactor Analyst

ITEMS OPENED AND CLOSED

Opened

50-327, 328/01-03-03	URI	Failure to Implement 2B-B EDG Maintenance Procedure (Section 4OA3.1).
50-328/01-03-05	URI	Failure to Realign Boric Acid Tank Flow Path to the RCS (Section 4OA3.3).

Opened and Closed

50-327/01-03-01	NCV	Failure to Promptly Identify and Subsequently Correct Valve Seat Leakage (Section 1R15).
50-328/01-03-02	NCV	Failure to Follow RHR Performance Test Procedure (Section 1R22).
50-327/01-03-04	NCV	Failure to Adequately Maintain Abnormal Operating Procedure for RCP Malfunctions (Section 4OA3.2).
50-328/01-03-06	NCV	Failure to Close Sample Valve for Boric Acid Storage Tank B (Section 4OA7).