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

May 1, 2000

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: NRC INTEGRATED INSPECTION REPORT NO. 50-327/00-02 AND 50-328/00-02

Dear Mr. Scalice:

On April 1, 2000, the NRC completed an inspection at your Sequoyah 1 & 2 reactor facilities. The enclosed report presents the results of this inspection.

The inspection was an examination of 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. Within these areas the inspection consisted of a selective examination of procedures and representative records, observations of activities, and interviews with personnel. Specifically, the inspection covered routine resident inspections and an announced inspection by a region based reactor inspector.

The NRC identified three findings of low safety significance that have been entered into your corrective action program and are discussed in the summary of findings and in the body of the attached inspection report. Of the three findings, two were determined to involve violations of NRC requirements, but because of their low safety significance the violations are not cited. If you contest these non-cited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, 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 the Sequoyah facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document 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 w/attachment A

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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:	50-327/00-02, 50-328/00-02
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Sequoyah Nuclear Plant, Units 1 & 2
Location:	Sequoyah Access Road Hamilton County, TN 37379
Dates:	February 13, 2000 through April 1, 2000
Inspectors:	R. Gibbs, Senior Resident Inspector R. Starkey, Resident Inspector R. Telson, Resident Inspector W. Bearden, Reactor Inspector (Sections 1R08, 1R09, 1R19) D. Thompson, Safeguards Inspector (Section 4OA4.5)
Approved by:	P. Fredrickson, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

Sequoyah Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-327/00-02, 50-328/00-02

The report covers a seven-week period of resident inspection. In addition, it includes the results of a region based reactor inspector associated with Unit 1 inservice inspection activities.

The significance of issues is indicated by their color (green, white, yellow, red) and was determined by the NRC's Significance Determination Process, as discussed in the attached summary of the NRC's Reactor Oversight Process.

Cornerstone: Initiating Events

- Green. Unit 1 experienced an automatic turbine trip and subsequent reactor trip while returning to full power following the Unit 1 Cycle 10 refueling outage. The reactor trip was caused by an erroneous "main generator loss-of-excitation field" protective signal. The erroneous protective signal was the result of errors in a design change specifications package which caused the protective circuitry to be incorrectly wired and tested. The finding represented a low risk significance because although the design change errors contributed to the likelihood of a reactor trip they did not affect the availability of any mitigating systems. (Section 40A3.2)

Cornerstone: Mitigating Systems

- Green. A non-cited violation of 10 CFR 50 Criterion XVI, with three examples, was identified for failure to correct problems identified in 1995, 1996, and 1998 with administrative controls for the handling and storage of bulk lubricants. The failure contributed to the 1998 and 1999 installation of a lubricant not meeting vendor and equipment qualification binder requirements into emergency core cooling system and other safety related components. Multiple and diverse safety-related systems were impacted over a period exceeding one year. The finding had low risk significance because it did not result in an actual loss of safety function in the systems identified. (Section 1R15)

- Green. A non-cited violation of Technical Specification 4.3.2.1.3 was identified for failure to perform the required response time test for refueling water storage tank (RWST) level transmitter 1-LT-63-53. The instrument was subsequently tested with satisfactory results. The finding represented low risk significance because the function of the transmitter to swap emergency cooling water systems pump suction to the containment sump on low RWST level was not impacted.

- TBD. An unresolved item was identified involving the failure to identify and resolve deficiencies in an operating procedure used to vent residual heat removal system discharge piping following an incident in 1998 in which the adequacy of the procedure was challenged. This inadequate procedure and the failure of a relief valve to reseat resulted in a loss of reactor coolant inventory event while Unit 1 was shutdown in Mode 5. An estimated 10,000 gallons of reactor coolant was discharged to the pressurizer relief tank. However, the risk significance determination for the deficient shutdown condition procedure was not completed at the end of the inspection period. (Section 4OA3.1).

Report Details

Unit 1 began the inspection period at 86 percent power coasting down to the scheduled March 2000 Cycle 10 refueling outage. On February 22, the unit was shutdown. The unit was restarted on March 17 and the main generator was synchronized to the grid on March 18, ending the refueling outage. On March 21, during power ascension, the unit received an automatic reactor trip from 76 percent power. The unit was placed in Mode 3 until March 22 when it was restarted and synchronized to the grid. Power was increased to approximately 60 percent and held pending repairs to main feedwater pump 1B. Power was subsequently increased to 100 percent on March 29 where it remained for the remainder of the inspection period.

Unit 2 operated at or near 100 percent power for the entire inspection period.

1. REACTOR SAFETY

1R03 Emergent Work

a. Inspection Scope

The inspectors evaluated the licensee's work prioritization and risk determination associated with selected activities, listed below, to determine, as appropriate, whether necessary steps were planned, controlled, and executed.

- Temporary repair to a leaking thermal relief valve fitting on the B-train spent fuel pool component cooling water heat exchanger outlet shortly after the Unit 1 core had been offloaded to the spent fuel pool

- Removal of foreign material in the Unit 1 reactor cavity

b. Observations and Findings

No findings were identified and documented through this inspection.

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, as appropriate, consideration of plant procedures and reviews of documents to determine correct system lineups, and verification of critical components to identify any discrepancies which could affect operability of the redundant train or backup system.

- B-train auxiliary building gas treatment system during an A-train outage

- Source range channel N32 during an N31 outage

- Fuel pool cooling system (both trains) while Unit 1 reactor core was fully off-loaded

- Off-site & emergency power supplies during critical Unit 1 outage configurations (e.g., mid-loop operations)

b. Observations and Findings

No findings were identified and documented through this inspection.

1R05 Fire Protection Walkdowns

a. Inspection Scope

The inspectors conducted tours of areas important to reactor safety, listed below, to evaluate, as appropriate, conditions related to (1) licensee 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.

- Auxiliary building (690' elevation)

- Auxiliary building (714' elevation)

- Auxiliary building (734' elevation)

b. Observations and Findings

No findings were identified and documented through this inspection.

1R08 Inservice Inspection Activities

a. Inspection Scope

The inspectors evaluated inservice inspection (ISI) and repair and replacement activities during the ongoing Unit 1 refueling outage to determine the effectiveness of the licensee’s American Society of Mechanical Engineers (ASME) Section XI ISI Program. Activities included review of radiographs of completed welding on chemical and volume control system piping, observation of eddy current testing of steam generator tubes, and observation of flourescent magnetic particle and ultrasonic examinations of reactor vessel components The inspectors evaluated compliance with ASME code requirements, reviewed non-destructive (NDE) methods, reviewed NDE examiner qualifications, and evaluated NDE inspection results. The inspectors also reviewed several notification of indication reports and verified that identified problems were entered into the licensee’s corrective action program as applicable.

b. Observations and Findings

No findings were identified and documented through this inspection.

1R09 Inservice Testing of Pumps and Valves

a. Inspection Scope

The inspectors reviewed inservice testing of selected risk significant mitigating system pumps and valves, listed below, to evaluate the effectiveness of the licensee's ASME Section XI Inservice Testing (IST) Program to determine equipment availability and reliability. The inspectors evaluated, as appropriate, (1) testing procedures, (2) acceptance criteria, (3) testing methods, (4) compliance with the licensee's IST Program, technical specifications (TS), and code requirements, (5) range and accuracy of test instruments, and (6) required corrective actions.

- 0-SI-SXP-070-201.C, CS CCS Pump and 0-70-504 Check Valve Test
- 1-SI-SXP-074-201.B, Residual Heat Removal Pump 1B-B Performance Test
- 2-SI-SXP-003-201.A, Motor Driven Auxiliary Feed Water Pump 2A-A Performance Test
- 0-SI-SXV-001-266.0, ASME Section XI Valve Testing, (Unit 1 Main Steam Line Isolation Valves Stroke Time Test)
- 1-SI-SXV-063-202.0, Safety Injection Hot Leg Secondary Check Valve Integrity Test
- 1-SI-SXV-063-203.0, RHR Hot Leg Secondary Check Valve Integrity Test
- 1-SI-SXV-063-205.0, Safety Injection Cold Leg Secondary Check Valve Integrity Test
- 1-SI-SXV-063-206.0, RHR Cold Leg Primary & Secondary Check Valve Integrity Test
- 1-SI-SXV-063-207.0, SI Cold Leg Accumulator Secondary Check Valve Integrity

b. Observations and Findings

No findings were identified and documented through this inspection.

1R12 Maintenance Rule Implementation

a. Inspection Scope

The inspectors reviewed portions of the auxiliary feedwater (AFW) system, specifically motor-driven AFW pump 2A-A, as a result of performance-based problems, to assess the effectiveness of associated maintenance efforts. The inspectors reviewed: (1) Maintenance Rule scoping; (2) characterization of failed components; (3) safety significance classifications; (4) 10 CFR 50.65 (a)(1) or (a)(2) classifications; and (5) the appropriateness of performance criteria, goals, and corrective actions.

b. Observations and Findings

No findings were identified and documented through this inspection.

1R13 Maintenance Work Prioritization and Control

a. Inspection Scope

The inspectors evaluated, as appropriate for the selected SSCs listed below, (1) the effectiveness of the risk assessments performed before maintenance activities were conducted; (2) the management of risk; (3) that, upon identification of an unforseen situation, necessary steps were taken to plan and control the resulting emergent work activities; and (4) that maintenance risk assessments and emergent work problems were adequately identified and resolved.

- Temporary repair to a leaking thermal relief valve fitting on the B-train spent fuel pool component cooling water heat exchanger outlet shortly after the Unit 1core had been offloaded to the spent fuel pool

- Effects of Unit 1 loss of offsite power and safety injection (SI) test (0-SI-OPS-082-026.a) on Unit 2 scheduled maintenance

b. Observations and Findings

No findings were identified and documented through this inspection.

1R14 Personnel Performance During Non-routine Plant Evolutions and Events

a. Inspection Scope

The inspectors reviewed, as described below, (1) personnel performance during selected non-routine events and/or transient operations, (2) licensee event reports focusing on those events involving personnel response to non-routine conditions, and (3) operator response after reactor trips which required more than routine expected operator responses, or which involved operator errors. As appropriate, the inspectors: (1) reviewed operator logs, plant computer data, or strip charts to determine what occurred and how the operators responded; (2) determined if operator responses were in accordance with the response required by procedures and training; (3) evaluated the occurrence and subsequent personnel response using the significance determination process (SDP); and (4) confirmed that personnel performance deficiencies were captured in the licensee's corrective action program.

.1 Unit 1 Cycle 10 Refueling Outage

- Power reduction and manual reactor trip initiating the U1C10 refueling outage
- Reactor cool-down operations
- Reduced inventory and mid-loop operations
- Refueling activities
- Unit restart activities
- Power ascension

b. Observations and Findings

No findings were identified and documented through this inspection.

.2 Loss of Reactor Coolant Event While Shutdown

b. Observations and Findings

On March 13, a loss of reactor coolant system (RCS) inventory occurred while Unit 1 was in Mode 5 making preparations to transition to Mode 4 at the conclusion of the refueling outage. During this time operators initiated an operating procedure to vent the residual heat removal (RHR) discharge piping with an RHR pump running. This evolution resulted in the actuation of a relief valve in the RHR pump discharge flow path. The relief valve subsequently failed to reseat which resulted in an estimated 10,000 gallons of reactor coolant being discharged to the pressurizer relief tank (PRT). Coolant overflowed onto the primary containment floor when the PRT's available capacity was exceeded, and the PRT rupture disc opened. No operator performance issues were identified and documented through this inspection. Other findings related to this event are discussed in Section 40A3.1.

.3 Unit 1 Reactor Trip While Increasing Power Following Refueling Outage

b. Observations and Findings

On March 21, Unit 1 experienced a spurious automatic reactor trip from 76 percent power while plant personnel were returning the unit to 100 percent power following the

Unit 1 Cycle 10 refueling outage. The reactor trip occurred due to a turbine trip which was caused by an erroneous “main generator loss-of-excitation field” protective signal. The inspectors’ review of appropriate logs, plant records, and the licensee’s post-trip assessment confirmed that operators had promptly stabilized the unit in Mode 3 (hot shutdown).

Section 4OA3.2 discusses findings related to this event. No findings related to operator performance were identified and documented through this inspection

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed selected operability evaluations affecting risk significant mitigating systems, listed below, 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; (5) where continued operability was considered unjustified, the impact on TS LCOs and the risk significance in accordance with the SDP.

The four Technical Operability Evaluations (TOEs) listed in the table below were reviewed. Each addressed past operability and reportability concerns when the motors of safety-related emergency core cooling system (ECCS) components were discovered to contain lubricants not meeting vendor specifications and environmental qualification (EQ) binder requirements. TOE 0-00-063-0241 addressed extent-of-condition concerns and PER 00-000241, issued on January 10, 2000, addressed corrective actions.

TOE #	Impacted Component	Original Fill Date	Discovery Date	TOE Issue Date
0-00-063-0241	1B-B Safety Injection Pump Motor	August 4, 1998	December 21, 1999	January 14, 2000
1-00-072-0549	1B-B Containment Spray Pump Motor	August 3, 1998	January 18, 2000	January 21, 2000
1-00-062-1824	1A-A Centrifugal Charging Pump Motor	February 24, 1999	February 11, 2000	March 7, 2000
2-00-072-2953	2B-B Containment Spray Pump Motor	November 12, 1998	March 30, 2000	March 31, 2000

b. Observations and Findings

An NCV of 10 CFR 50 Criterion XVI, with three examples, was identified for failure to correct problems identified in 1995, 1996, and 1998 with administrative controls for the handling and storage of bulk lubricants. The failure contributed to the 1998 and 1999 installation of a lubricant not meeting vendor and EQ binder requirements into ECCS and other safety related components. Multiple and diverse safety-related systems were impacted over a period exceeding one year. This finding was screened to Green in Phase 1 of the SDP because it did not result in an actual loss of safety function in the systems identified.

Based on a review of maintenance records, TOE 0-00-063-0241 determined incorrectly that only one TS EQ motor was using off-specification (wrong) lubricant. The extent-of-condition determination and associated maintenance records were later shown to be inaccurate. The wrong lubricant was traced to one of two bulk storage and dispensing containers labeled to contain the grade of lubricant (STO-2) used in 22 safety-related components including both trains of both units' high-, intermediate-, and low-head safety injection. The bulk storage and dispensing containers were periodically refilled from original vendor shipping drums using a common pump and hose arrangement. According to the licensee, one of the containers had become cross-contaminated through human error approximately two years prior to the December 1999 discovery of the wrong lubricant in the SI pump 1B-B motor.

At the conclusion of the inspection: (1) five safety related systems had been confirmed impacted; (2) identification of impacted systems (lubricant sampling) was in progress and scheduled to be completed in May 2000; (3) the contaminated bulk storage and dispensing container had been removed from service; (4) interim administrative controls for the handling and storage of bulk lubricants were put into place; and (5) PER 0-00-063-0241, addressing extent of condition and corrective actions, remained open.

The inspectors reviewed the licensee's corrective action program for prior issues related to administrative controls for storage and handling of bulk lubricants and found the following three PERs, the last of which was closed in March 1999:

- SQ950203PER, initiated in March 1995, addressed lack of controls to ensure traceability of oil stored in a remote operations storage cabinet.

- SQ960370PER, initiated in February 1996, addressed inconsistencies in the lube oil bulk storage room related to container labeling and information on container fill logs and other documentation.

- SQ980951PER, initiated in July 1998, addressed identified problems with chemical labeling and questions involving the administrative controls of bulk lubricants.

The inspectors observed that (1) a human error exposed 22 safety-related components including all trains of ECCS and motor driven auxiliary feedwater pumps to an increased common-mode failure potential over a period exceeding one year, (2) administrative controls for the handling and storage of bulk lubricants were not adequate to prevent or identify such an error in a timely fashion, (3) quality assurance maintenance records were not adequate to accurately identify which components had been impacted, (4) multiple opportunities were identified to correct deficiencies over the past several years, and (5) no actual loss of safety function has been identified in the impacted components identified to date.

The licensee successfully demonstrated that operability of the affected equipment was not affected. Because there was no loss of safety function the finding was screened to Green using Phase 1 of the SDP.

10 CFR 50, Appendix B, Criterion XVI, Corrective Action, states in part that conditions adverse to quality shall be promptly identified and corrected. Contrary to the above, PERs initiated in 1995, 1996, and 1998, which identified problems with inadequate administrative controls for the handling and storage of bulk lubricants, conditions adverse to quality, were closed without effective corrective action. As a result, the lubricant in a bulk storage and dispensing container became cross-contaminated and a lubricant not meeting vendor and EQ binder requirements was installed in multiple ECCS and other safety related systems. The NRC is treating this violation as an NCV, consistent with the Interim Enforcement Policy for pilot plants. This violation is in the licensee's corrective action program as PER SQ 00-000241-00. The violation is identified as NCV 50-327,328/00-02-01, Failure to Correct Identified Deficiencies in Administrative Controls for the Handling and Storage of Bulk Lubricants Contributing to the Installation of Wrong Lubricants into ECCS and other Safety-Related Systems.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed post maintenance test (PMT) procedures 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; (8) and that equipment was returned to the status required to perform its safety function.

- 1-SI-SFT-063-001.0, SI System Hot Leg and Cold Leg Injection Flow Test, following installation of charging and SI system flow orifices
- 0-MI-MXX-061-003.0, IC Maintenance Inspection
- 0-MI-MXX-061-101.0, IC Ice Servicing
- 1-SI-SFT-062.001.0, Charging Pump Injection Flow Test
- Unit 1 RWST level transmitter 1-LT-63-53

b. Observations and Findings

No findings were identified and documented through this inspection.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors observed numerous activities associated with the Unit 1 Cycle 10 refueling outage. These activities are listed below.

Clearance Activities - Checked tags properly hung and equipment appropriately configured to support the function of the clearance:

- Tagout: 1-TO-2000-0001, Section: 1-62-0058A-RFO
- Tagout: 1-TO-2000-0001, Section 1-74-0156-RFO, RHR HX Return to RWST

Reactor Coolant System Instrumentation - Checked RCS pressure, level, and temperature instrumentation installed and configured to provide accurate indication and that instrument error was accounted for:

- 1-PI-IXX-068-005.0, Installation and Removal of the Mansell Level Monitoring System
- Engineering assistance request (EAR) 2000-NSS-068-1285, Benchmark Change to the Mansell Level Monitoring System Channel “B”
- EAR 2000-NSS-068-1287, Benchmark Change to the Mansell Level Monitoring System Channel “A” and Channel “B”

Electrical Power - Checked that status and configurations of electrical systems met TS requirements and the outage risk control plan and that switchyard activities were controlled commensurate with safety and the outage risk control plan assumptions.

Decay Heat Removal (DHR) System Monitoring - Observed DHR parameters to assess proper system function and that the steam generators, when relied upon, were a viable means of backup DHR.

Spent Fuel Pool Cooling System Operation - Assessed outage work for potential impact on the ability of the operations staff to operate the spent pool cooling system during and after core offload.

Inventory Control - Reviewed flow paths, configurations, and alternative means for inventory addition for consistency with the outage risk plan. Reviewed activities with the potential to cause loss of inventory for adequacy of controls to prevent inventory loss.

Reactivity Control - Evaluated licensee control of reactivity for compliance with TS. Also evaluated activities or SSCs for potential to cause unexpected reactivity changes for inclusion and proper control under the outage risk plan.

Containment Closure - Reviewed control of containment penetrations for compliance with refueling operations TS and to ensure that containment closure could be achieved during selected configurations.

Reduced Inventory and Mid-Loop Conditions - Reviewed numerous activities associated with reduced inventory and mid-loop operations with emphasis on the licensee's ability to monitor and control RCS water level. Also evaluated the effect of distractions on operator ability to maintain required reactor vessel level during mid-loop operations.

Refueling Activities - Reviewed fuel handling operations (removal, inspection, and insertion) and other ongoing activities for conformance with TS and approved procedures. Confirmed that the location of fuel assemblies was tracked from core offload through core reload.

Monitoring of Heatup and Startup Activities - Reviewed on a sampling basis that TS and administrative procedure prerequisites for mode changes were met prior to changing modes or plant configurations. The inspectors walked down containment prior to reactor startup to verify that debris had not been left which could affect performance of the containment sumps.

b. Observations and Findings

Inventory Control

On March 13, a loss of RCS inventory occurred while Unit 1 was in Mode 5 making preparations to transition to Mode 4 at the conclusion of the refueling outage. A description of the event, findings from the event, and the operator actions related to this event are discussed in Sections 40A3.1 and 1R14.2.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed surveillance tests and/or reviewed test data of selected risk-significant SSCs, listed below, to assess, as appropriate, whether the SSCs met TS, updated final safety analysis report (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.

- 0-SI-NUC-000-038.0, Shutdown Margin Calculation for Modes 3, 4, 5
- 0-SI-SXX-068-127.0, RCS Pressurizer Temperature and Pressure Limits
- 0-PI-SXV-001.0, Stroke Testing of MSIVs at Operating Temperature
- 0-SI-OPS-000-187.0, Containment Inspection
- 0-SI-OPS-082-026.a, Loss of Offsite Power with Safety Injection-D/G 1A-A Test
- SI-106.2, Ice Condenser (IC) - Ice Bed, Unit 1
- SI-106.4, IC Ice Weighing, Unit 1

- SI-108.4, IC Intermediate and Lower Inlet Doors, Vent Curtains and Door Seals, Unit 1
- 2-SI-SXP-072-201.B, Containment Spray Pump 2B-B Performance Test
- 1-SI-SFT-063-001.0, Safety Injection System Hot Leg and Cold Leg Injection Flow Test.
- 1-SI-SFT-062-001.0, Charging Pump Injection Flow Test

b. Observations and Findings

No findings were identified and documented through this inspection.

4 OTHER ACTIVITIES

4OA3 Event Followup

a. Inspection Scope

The inspectors evaluated plant status and mitigating actions of the following events, listed below, to assess the need for increased inspection activity. Specifically, the inspectors, as appropriate, (1) observed plant parameters and status, (2) evaluated the performance of mitigating systems and licensee actions, (3) confirmed that the licensee properly classified the event and made timely and accurate notifications to the NRC as required, (4) communicated details regarding the event to risk analysts and others in Region and Headquarters offices for use in determining risk significance and NRC reactive response to the event.

.1 Unit 1 RCS Inventory Loss While Shutdown

b. Observations and Findings

An unresolved item (URI) was identified for failure to identify and resolve deficiencies in an operating procedure used to vent RHR system discharge piping following an incident in 1998 in which the adequacy of the procedure was appropriately challenged. This inadequate procedure and the failure of a relief valve to reseat resulted in a loss of reactor coolant inventory event while Unit 1 was shutdown in Mode 5. An estimated 10,000 gallons of reactor coolant was discharged to the PRT. However, the risk significance of the deficient procedure had not been determined at the end of the inspection period.

On March 13, Unit 1 was in shutdown condition Mode 5, making preparations to transition to Mode 4 at the conclusion of the refueling outage. The RCS was at 360 psig and 145 degrees F with pressurizer (PZR) level at 76 percent. At 11:51 p.m., operators initiated Procedure 1-SI-OPS-074-128.0, Rev 3, Unit 1 RHR Discharge Piping Vent, to vent the RHR discharge piping with the RHR pump running. The operators expected a PZR level drop of up to 15 percent.

At 12:17 a.m. with pressurizer level approaching 23 percent and decreasing, operators entered Abnormal Operating Procedure (AOP) R.02, Shutdown LOCA. By 12:25 a.m., the PZR level had reached 12 percent and stabilized. At that time, AOP R.02 had been completed. At 12:35 a.m. operators initiated a manual phase A and containment vent isolation, an engineered safety feature actuation. By 12:57 a.m. operators had stabilized the unit in Mode 5 at 130 psig and 145 degrees F with PZR level at 40 percent. An estimated 10,000 gallons of reactor coolant were discharged to the PRT during the event. According to the licensee, about 2000 gallons of RCS water overflowed onto the primary containment floor when, at 12:39 a.m. the PRT's capacity was exceeded, and the PRT rupture disc opened.

The unanticipated decrease in PZR level was caused by the failure of a relief valve in the RHR pump discharge flow path, believed by the licensee to be valve 62-626, to reseat promptly following its actuation. The actuation was caused by a pressure pulse that occurred when operators redirected RHR flow with a running pump and partially voided the hot leg SI line. Subsequent testing of the relief valve confirmed the valve lifted as designed at approximately 600 psig. The lowest observed PZR level was 11 percent and operators were not required to start a second charging pump or any other ECCS equipment to recover PZR level. The relief valve was isolated and replaced following the event. Since the relief valve could be isolated, the potential for continued loss of inventory during the event was very low. In addition, the other train of RHR shutdown cooling was available had it been required. The licensee's investigation continues about why the valve failed to reseat promptly. The inspectors reviewed operating logs, plant status reports, plant computer information, and conducted discussions with plant personnel to confirm the facts associated with the event described above.

Deficiencies in 1-SI-OPS-074-128.0 had caused operators to manipulate the RHR system while venting without proper controls for flow rates. Rapid changes in flow rates caused pressure pulses (water hammer) in RHR and SI system piping. The licensee believed these pressure pulses challenged SI system relief valve 62-626 which lifted and failed to promptly reseat. This established a path from the RCS to the PRT. The procedure deficiencies had existed since the procedure was revised in February of 1997 to permit RHR system venting with RHR pumps operating. The inspectors determined that the licensee's assessment of the event to date was reasonable.

The inspectors reviewed problem evaluation report (PER) SQ 981446PER which was initiated in October of 1998 when operators observed an unexpected PZR level decrease of approximately nine percent while venting the Unit 1 RHR hot leg piping. The PER initiator questioned the adequacy of the procedures used to fill and vent the RHR system. As a result, changes were made to a number of procedures including both 1- and 2-SI-OPS-074-128.0. The inspectors determined the licensee did not fully address the extent of condition related to the adequacy of the procedures at that time. A note was added to alert operators to expect up to a 15 percent PZR level decrease when performing the procedure due to filling of voided SI piping. The corrective actions did not consider the effects of a potential water hammer condition when the voided pipe was filled. The PER was closed on June 2, 1999.

10 CFR 50, Appendix B, Criterion XVI, Corrective Action, requires, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to the above, PER SQ981446PER, initiated in October 1998 to question the adequacy of RHR system vent and fill procedures, was closed on June 2, 1999 without correcting a condition adverse to quality. Revisions to Procedures 1 and 2-SI-OPS-074-128.0 "Unit 1(2) RHR Discharge Piping Vent," failed to correct procedural deficiencies which subjected RHR and SI system piping to potentially damaging pressure surges and unnecessarily challenged SI system relief valves contributing to a loss of reactor coolant inventory event on March 13. The risk significance of the deficient procedure was not determined at the end of the inspection period. Pending completion of this determination, this issue is identified as URI 50-327,328/00-02-02, Failure to Identify and Correct Deficiencies in Procedures to Vent RHR System Discharge Piping Contributing to a Shutdown Loss of Coolant Inventory Event. The licensee entered the issue in their corrective action program as PER 00-2224.

.2 Unit 1 Reactor Trip While Increasing Power Following Refueling Outage

b. Observations and Findings

Unit 1 experienced an automatic turbine trip and subsequent reactor trip while returning to full power following the Unit 1 Cycle 10 refueling outage. The reactor trip was caused by an erroneous "main generator loss-of-excitation field" protective signal. The erroneous protective signal was the result of errors in a design change specifications package which caused the protective circuitry to be incorrectly wired and tested. This finding was determined to be Green representing low safety significance because although the design change errors contributed to the likelihood of a reactor trip they did not affect the availability of any mitigating systems.

On March 21, Unit 1 automatically tripped from 76 percent reactor power while plant personnel were returning the unit to 100 percent power following the Unit 1 Cycle 10 refueling outage. The reactor tripped due to a turbine trip which was caused by an erroneous "main generator loss-of-excitation field" protective signal. The inspectors reviewed the licensee's event investigation and discussed the event with plant personnel to confirm the licensee's findings. Through this inspection the inspectors agreed with the licensee's initial conclusion that the trip was the result of errors in the design change specifications package which caused the loss-of-excitation field protective circuitry to be incorrectly wired and tested. The licensee initiated PER 00-002540-000 to determine the cause and address appropriate corrective actions. The inspectors evaluated the issue for risk significance using the SDP process. Although the errors in the design change process contributed to the likelihood of a reactor trip, the errors did not affect the availability of mitigating systems and was therefore screened to Green in Phase I of SDP.

During the trip, the secondary plant experienced several challenges resulting in the failure of the 1B main feedwater pump assembly due to excessive vibration. The licensee determined that the cause of the damage was due to (1) leakage of the high pressure steam supply stop valve, (2) a feedwater heater string isolation, and (3) opening of the main feed water pump recirculation valve. At the end of the inspection period, the inspection necessary to determine whether these equipment performance issues were acceptable and also the risk determination of the issues, had not been completed. Pending completion of the issues inspection and risk determination, these issues are collectively identified as URI 50-327/00-02-03, Challenges to Secondary Plant Systems After Unit 1 Reactor Trip.

4OA4 Other

.1 Temporary Instruction 2515/142, Draindown During Shutdown And Common-Mode Failure

a. Inspection Scope

The inspectors reviewed the licensee's response to GL 98-02 to confirm that the licensee: (1) had evaluated 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 emergency core cooling system (ECCS) pumps, and if found susceptible, (2) had taken reasonable measures to reduce the likelihood of a draindown similar to that of a Wolf Creek event, which occurred on September 17, 1994. Specifically, the inspectors reviewed implementation of the licensee's documented operating practices and procedures, and training requirements performed to support implementation of their quality assurance program.

b. Observations and Findings

The inspectors observed two areas in which operator training and administrative controls could have provided additional reasonable assurances against the risks associated with a Wolf Creek-type event. Specifically, (1) operators did not receive enhanced training to alert them to the potential for an RCS blowdown resulting in a common-cause failure of the RHR and ECCS system pumps should a misalignment of hand control valve, HCV 74-34, the RCS-to-RWST dump valve, occur when shutdown cooling is in service at elevated RCS temperatures; and (2) administrative controls did not require an additional position verification, placement of a hold order or placard attached to HCV 74-34 to ensure that it remained locked shut at elevated RCS temperatures with RHR shutdown cooling in service.

The inspection focused on HCV 74-34, which, if inappropriately open or opened prematurely during RHR shutdown cooling, could provide an 8" diameter pathway for hot pressurized water (285 to 350 degrees F at approximately 550 psig combined RHR pump head and RCS pressure) to be discharged via a common ECCS pump suction header to the RWST. The inspectors reviewed a licensee analysis which indicated that supplying ECCS equipment with water at indicated temperatures in excess of 235 degrees F could render the equipment inoperable.

The inspectors found potential enhancements in the licensee’s response to the issue because training and administrative controls narrowly focused on the risk associated with RHR pump cavitation during reduced inventory operations when the RCS was cold and depressurized. As a result:

- Training did not specifically address the potential to simultaneously bypass containment nor did it address the potential to render ECCS equipment inoperable during a Wolf Creek-type draindown scenario due to inadvertent operation of the HCV-74-34 under hot, pressurized RCS conditions. The inspectors determined that not including this content in operator training increased the susceptibility to a Wolf Creek-type event.

- An administrative hold order blocking HCV 74-34 shut was used only during reduced inventory conditions--not under the hot, pressurized conditions which presented the greatest risk of a Wolf Creek-type event. The inspectors noted, however, that the practice of maintaining the valve in a locked closed condition under the licensee's locked valve/breaker program and a precaution in the RHR system operating procedures directing that HCV-74-34 not be opened while on RHR shutdown cooling with RCS temperature greater than 235 degrees F, were significant deterrents to inadvertent operation of the valve.

After reviewing the issue and GL 98-02 with the licensee, PER 00-001404-000 was issued on February 2, 2000, to address potential enhancements to (1) increase administrative controls on HCV-74-34 by verifying its position each time RHR is placed in service and to (2) enhance the guidance for annunciator "RWST Make-Up Shutoff" to specifically identify HCV-74-34 as a source of RHR in-leakage to the RWST and to identify the potential for high RWST temperatures to render ECCS equipment inoperable.

The inspectors determined that the licensee's previous and planned corrective actions to GL-98-02 mitigated but were not fully effective in minimizing the likelihood of a draindown event similar to that of Wolf Creek. The licensee's response did not fully address the potential risks associated with hot, pressurized RCS conditions. Pending further NRC review of the issues described above to determine their risk significance and regulatory impact, this issue is identified as URI 50-327, 328/00-02-04, Risk Significance and Regulatory Impact of Issues Related to TI-142 Inspection.

.2 <u>(Closed) Licensee Event Report (LER) 50-327/2000-001-00</u>: Failure to perform response time testing on a refueling water storage tank (RWST) level transmitter. On January 16, 2000, maintenance personnel were unable to successfully calibrate refueling water storage tank (RWST) level instrument 1-LT-63-53 within the acceptance criteria of its calibration procedure, 1-SI-ICC-063-053.4. To comply with TS 3.3.2.1, the transmitter's associated channel (channel IV) was placed in bypass. On January 17, 2000, the licensee replaced the transmitter under work order (WO) 00-000423-000. The PMT associated with the WO included a calibration and a channel check which were performed successfully. The level instrument was returned to service later that day and TS 3.3.2.1 was exited.

On January 18, 2000, the licensee determined that the transmitter was returned to service improperly. TS surveillance 4.3.2.1.3 required performance of a response time test to demonstrate operability. This test was not performed before the transmitter was declared operable on January 17. The licensee entered TS 3.0.3 because the six hour LCO to place the transmitter's associated instrument channel in bypass was exceeded. Shortly afterwards, the channel was placed in bypass and TS 3.0.3 was exited. Later that day the response time test was successfully completed and the 1-LT-63-53 was declared operable. The inspectors reviewed plant operating logs, work order packages, corrective action program entries, and discussed the item with licensee personnel to confirm the facts associated with the issue.

Using the SDP, the inspectors evaluated the risk significance of the failure to perform the response time test. Because the replaced transmitter passed its response time test on January 18, the function of the transmitter was not lost. If a loss of coolant accident had occurred before the transmitter was successfully tested, the RWST level instrumentation would have transferred suction of emergency core cooling systems to the containment sump as required during a low water level condition in the RWST. The issue was therefore screened as Green in Phase 1 of SDP.

Failure to perform the response time test before the 1-LT-63-53 was returned to service is a violation of TS 4.3.2.1.3. The NRC is treating this violation as an NCV, consistent with the Interim Enforcement Policy for pilot plants. This violation is in the licensee's corrective action program as PER 00-000430-00. This item is identified as NCV 50-327/02-05, Failure to Perform Response Time Test for RWST Level Transmitter 1-LT-63-53.

.3 <u>(Closed) LER 50-328/2000-001-00</u>: Reactor trip caused from a low-low steam generator level resulting from a static switch control board circuit failure. A special inspection team was formed to investigate the circumstances associated with the reactor trip and safety injection. The results of that inspection are documented in NRC Special Inspection Report 50-328/00-03.

.4 <u>(Closed) LER 50-328/2000-002-00</u>: Inoperability of both SI pumps as a result of personnel error during performance of a maintenance activity. This issue was associated with an oil change that occurred on the 2B-B SI pump motor while the 2A-A SI pump was tagged out-of-service for routine maintenance. The maintenance technician was supposed to change the oil in the 2A-A pump motor, but mistakenly changed the oil in the 2B-B pump. This action rendered both pumps unavailable for about 30 minutes which resulted in the licensee entering TS 3.0.3. Further details of this issue are discussed in NRC Inspection Report 50-327,328/00-01.

.5 <u>(Closed) Licensee Event Report (LER) 50-327,328/1998 S01 00:</u> Failure of a safeguards system for which compensatory measures were not employed. The inspector conducted an in-office review of the LER and noted that, at 1143 a.m., June 10, 1998, while maintenance work was in progress the uninterruptible power supply (UPS) and output breaker were tripped resulting in loss of the security system. During posting of compensatory measures due to the loss of the security system the licensee failed to post a security officer within 10 minutes at one of the vital doors. Paragraph 10.1.2 of the Physical Security Plan, Revision 0, dated November 20, 1995, states: "Should a VA [vital area door] or hatch Intrusion Detection System (IDS) fail to perform the function for which it is intended, a MSF [member of the security force] shall be utilized to control access to the door or hatch, or an equivalent IDS shall be activated." This failure constitutes a violation of minor significance and is not subject to formal enforcement action in accordance with Section IV of the NRC's Enforcement Policy.

The licensee entered the event in the corrective action program and took the proper actions to preclude events of a similar nature from recurring.

4OA5 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on April 12, 2000. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

M. Bajestani, Site Vice President
H. Butterworth, Operations Manager
E. Freeman, Maintenance and Modifications Manager
J. Gates, Site Support Manager
C. Kent, Radcon/Chemistry Manager
D. Koehl, Plant Manager
M. Lorek, Site Engineering Manager
B. O'Brien, Maintenance Manager
P. Salas, Manager of Licensing and Industry Affairs
J. Valente, Engineering & Support Services Manager

NRC

R. Bernhard, Region II Senior Reactor Analyst

ITEMS OPENED AND CLOSED

Opened

50-327,328/00-02-02	URI	Failure to Identify and Correct Deficiencies in Procedures to Vent RHR System Discharge Piping Contributing to a Shutdown Loss of Coolant Inventory Event. (Section 40A3.1)
50-327/00-02-03	URI	Challenges to Secondary Plant Systems After Unit 1 Reactor Trip. (Section 4OA3.2)
50-327,328/00-02-04	URI	Risk Significance and Regulatory Impact of Issues Related to TI-142 Inspection. (Section 40A4.1)

Opened and Closed

50-327,328/00-02-01	NCV	Failure to Correct Identified Deficiencies in Administrative Controls for the Handling and Storage of Bulk Lubricants Contributing to the Installation of Wrong Lubricants into ECCS and other Safety-Related Systems. (Section 1R15)
50-327/00-02-05	NCV	Failure to Perform Response Time Test for RWST Level Transmitter 1-LT-63-53. (Section 4.0A4.2)

Closed

50-327/2000-001-00	LER	Failure to Perform Response Time Testing on a Refueling Water Storage Tank (RWST) Level Transmitter. (Section 4OA4.2)
50-328/2000-001-00	LER	Reactor Trip Caused From a Low-Low Steam Generator Level Resulting From a Static Switch Control Board Circuit Failure. (Section 4OA4.3)
50-328/2000-002-00	LER	Inoperability of Both Safety Injection Pumps as a Result of Personnel Error During Performance of a Maintenance Activity. (Section 4OA4.4)
50-327,328/1998 S01 00	LER	Failure of a Safeguards System for which Compensatory Measures were not Employed (Section 4OA4.5)

Attachment: A

NRC's REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The process takes into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting safety performance at NRC licensed plants.

The process monitors licensee performance in three broad areas (called strategic performance areas): reactor safety (avoiding accidents and reducing the consequences of accidents if they occur), radiation safety (protecting plant employees and the public during routine operations), and safeguards (protecting the plant against sabotage or other security threats). The process focuses on licensee performance within each of seven cornerstones of safety in the three areas:

Reactor Safety

- Initiating Events
- Mitigating Systems
- Barrier Integrity
- Emergency Preparedness

Radiation Safety

- Occupational
- Public

Safeguards

- Physical Protection

To monitor these seven cornerstones of safety, the NRC uses two processes that generate information about the safety significance of plant operations: inspections and performance indicators. Inspection findings will be evaluated according to their potential significance for safety, using the Significance Determination Process, and assigned colors of GREEN, WHITE, YELLOW or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent little effect on safety. WHITE findings indicate issues with some increased importance to safety, which may require additional NRC inspections. YELLOW findings are more serious issues with an even higher potential to effect safety and would require the NRC to take additional actions. RED findings represent an unacceptable loss of safety margin and would result in the NRC taking significant actions that could include ordering the plant shut down.

Performance indicator data will be compared to established criteria for measuring licensee performance in terms of potential safety. Based on prescribed thresholds, the indicators will be classified by color representing incremental degradation in safety: GREEN, WHITE, YELLOW, and RED. The color for an indicator corresponds to levels of performance that may result in increased NRC oversight (WHITE), performance that results in definitive, required action by the NRC (YELLOW), and performance that is unacceptable but still provides adequate protection to public health and safety (RED). GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections.

The assessment process integrates performance indicators and inspection so the agency can reach objective conclusions regarding overall plant performance. The agency will use an Action Matrix to determine in a systematic, predictable manner which regulatory actions should be taken based on a licensee's performance. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action, as described in the matrix. The NRC's actions in response to the significance (as represented by the color) of issues will be the same for performance indicators as for inspection findings.