U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-327, 50-328
License Nos:	DPR-77, DPR-79
Report No:	50-327/98-10, 50-328/98-10
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Sequoyah Nuclear Plant, Units 1 & 2
Location:	Sequoyah Access Road Hamilton County, TN 37379
Dates:	October 11 through November 21, 1998
Inspectors:	D. Starkey, Acting Senior Resident Inspector R. Telson, Resident Inspector
Approved by:	H. Christensen, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

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EXECUTIVE SUMMARY

Sequoyah Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-327/98-10, 50-328/98-10

This integrated inspection included aspects of licensee operations, engineering, and maintenance. The report covers a 6-week period of resident inspection.

Operations

- Operators routinely demonstrated awareness, effective plant control, and management of transient conditions during a period which was characterized by a power ascension following the Unit 1 Cycle 9 refueling outage and two reactor trips with subsequent unit restarts (Section O1.1).

- The licensee continued to evaluate potential issues concerning the main bank transformer sudden pressure relay failures (Section O1.4).

- Operators and automatic plant systems controls maintained plant parameters within safety limits following a challenging Unit 1 reactor trip resulting from the loss of one channel of vital instrument power (Section O1.5).

- During the Unit 1 trip, operators were unaware that the steam generator safety valves were cycling continuously for a period of seventeen minutes due to a malfunction of the steam generator atmospheric relief valves (Section O1.5).

- The Plant Operations Review Committee thoroughly evaluated information presented by the Unit 1 post-trip review team and appropriately challenged the thoroughness of the review (Section O1.5).

- The licensee has implemented and maintained an adequate freeze protection program (Section O2.1).

- Operators failed to promptly validate Unit 1 reactor coolant system (RCS) chemistry samples which resulted in a delay in identifying an ongoing dilution event (Section M2.1).

Maintenance

- An NCV was identified for failure to follow procedure during maintenance activities on a diaphragm valve which resulted in an unplanned RCS boron dilution (Section M2.1).

- The licensee conducted a thorough root cause evaluation of the Unit 1 dilution event and initiated corrective actions to address mis-adjustment of diaphragm valves on other plant systems (Section M2.1).

- The stator core windings for emergency diesel generators 1B-B and 2B-B were not experiencing resistance increases of a magnitude that would result in an unsatisfactory functional performance (Section M8.1).

Engineering

- The licensee's engineering requirements for control of borated water external corrosion met the requirements of Generic Letter 88-05 (Section E8.2).

- The engineering risk evaluation regarding boric acid contamination on the exterior of the Unit 1 pressurizer was sound and conservative (Section E8.2).

Report Details

Summary of Plant Status

Unit 1 began the inspection period in power ascension, at approximately 75% power, following Cycle 9 refueling outage. The unit reached 100% power at 12:20 p.m. on October 12, 1998, where it remained until 11:39 a.m. on November 9 when the unit automatically tripped due to a failed vital instrument inverter. The inverter was repaired and the unit restarted, achieving criticality at 4:50 p.m on November 10, and 100% power at 10:00 p.m. on November 11. On November 20, power was reduced to 32% to permit a containment entry for inspection and repair of a leaking Loop 1 reactor coolant system (RCS) flow instrumentation vent valve. The partially open valve was closed by maintenance personnel and the unit returned to 100% power on November 21.

Unit 2 operated at full power until 5:01 a.m. on October 15 when the unit automatically tripped due to a failed main bank transformer sudden pressure relay which caused the main generator and turbine to trip. The failed relay had been recently replaced having failed on August 27, 1998, causing a reactor trip at that time as well (see NRC Inspection Report (IR) 50-327, 328/98-08). The sudden pressure relays were subsequently bypassed and the unit was restarted. The unit achieved criticality at 11:30 p.m. on October 15 and 100% power at 11:35 a.m. on October 17. The unit remained at full power for the remainder of the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was considered to be good. With the exception noted in Section O1.5, operators demonstrated awareness, effective plant control, and transient management during Unit 1 restart and two reactor trips with subsequent restarts.

O1.2 Review of World Association of Nuclear Operators (WANO) Report

During this inspection period the inspectors reviewed the WANO Peer Review of Sequoyah Nuclear Plant interim report dated September 18, 1998, for the assessment which was conducted in July 1998. A summary of the report was discussed with Region II management. At this time, additional follow up is not planned nor considered necessary.

O1.3 Request for Discretionary Enforcement

On November 10, 1998, the licensee requested discretionary enforcement to exceed by 48 hours the 24-hour action statement of Unit 2 Technical Specification (TS) 3.8.2.1, Action b. for the inoperable 120-Vac vital instrument power board 1-IV (See Section O1.5). The licensee concluded that troubleshooting and repair efforts on the inverter could exceed the 24-hours allowed outage time of the action statement. The request was based primarily on the fact that no Unit 2 safety-related loads were powered from the vital instrument bus 1-IV. The NRC granted enforcement discretion and compensatory measures implemented by the licensee were verified by the inspectors. The licensee completed repairs, testing, and restored the inverter to operable status at 11:56 a.m. on November 10, 1998. Discretionary enforcement, granted at approximately 10:25 a.m. that morning, was not required.

O1.4 Unit 2 Trip Due to Actuation of Main Bank Transformer Sudden Pressure Relay

a. Inspection Scope (71707)

The inspectors reviewed the Unit 2 trip which occurred as a result of the failure of the sudden pressure relay on the B phase of the main bank transformer.

b. Observations and Findings

On October 15, 1998, at 5:01 a.m., Unit 2 tripped automatically from 100% power following actuation of the B phase main bank transformer sudden pressure relay. The sudden pressure relay is designed to sense changes in the transformer's internal pressure and electrically isolates the transformer at unsafe rates of pressure rise. (A similar Unit 2 trip occurred on the same transformer on August 27, 1998, and was documented in IR 50-327, 328/98-08). The inspector reviewed the post trip report and concluded that all plant systems and equipment performed as designed during the unit trip.

The licensee's physical inspection of the relay identified that silicone oil had leaked out of the device. Troubleshooting found that the control bellows within the orifice had developed a leak resulting in a mismatch of the control bellows and actuation of the switch. Inspection at the licensee's laboratory determined that the leak was the result of vibration induced fatigue. The licensee's post trip oil analysis indicated that there were no problems in the transformer.

Following the unit trip, a temporary alteration change form (TACF) was implemented to remove the trip function from sudden pressure devices on all main bank and unit station service transformers on both units until a modification to the relays could be implemented. The licensee was evaluating whether to implement a design change notice (DCN) which would restore the generator trip function with a logic of "two-out-of-two" sudden pressure devices on the main transformers or whether to permanently disable the sudden pressure relays.

c. Conclusions

The licensee continued to evaluate potential issues with transformer sudden pressure relay failures.

O1.5 Unit 1 Automatic Reactor Trip Due to Failure of No. 1-IV Vital Inverter

a. Inspection Scope (71707)

The inspectors reviewed events related to an automatic trip of Unit 1. Inspectors observed the operators' immediate response in the control room, attended two Plant Operations Review Committee (PORC) meetings, observed corrective maintenance actions, reviewed the post trip report and observed plant restart.

b. Observations and Findings

An automatic trip of Unit 1 occurred on November 9, 1998, at 11:39 a.m. when the No. 1-IV 120-Vac vital instrument power inverter failed causing loss of power to the Channel-IV reactor protection circuits. Earlier in the day, Power Range Channel-II bistables had been placed in the tripped condition to conduct routine functional testing. The loss of Channel-IV coincident with Channel-II already in the tripped condition, provided the required 2/4 logic for an Over-Power Delta T reactor trip.

The inspectors responded immediately to the control room to observe as operators stabilized the unit in Mode 3. The inspectors confirmed through direct observations, discussions with operators, and review of plant documentation, that safety related plant systems, not powered from the 1-IV vital inverter, responded as designed to the reactor trip.

Main condenser steam dumps and steam generator atmospheric relief valves (ARVs) #2 and #3 failed shut upon loss of power as anticipated, as did pressurizer spray valves. However, the ARVs #1 and #4 did not open at 1040 psig as designed, resulting in a challenge to the steam generator safety valves.

Operators identified the steam dump system failure but did not recognize the malfunction of ARVs #1 and #4 or the abnormal steam generator pressures. In addition operators were unaware that the steam generator safety valves were cycling continuously for seventeen minutes. Instead of stabilizing at 1005 psig as anticipated, steam generator pressures increased to 1064 psig, the set point pressure for bank one of the steam generator safety valves, which subsequently cycled to maintain steam pressure within safety limits until electrical power was restored to the ARVs.

The elevated steam generator pressure resulted in higher-than-normal reactor coolant temperatures and a pressurizer insurge. The insurge combined with the failure of the pressurizer spray control system and isolation of the letdown system contributed to a challenge to the pressurizer power operated relief valve (PORV) which actuated at 2335 psig as designed to control reactor plant pressure within safety limits.

Although power was restored to the 1-IV vital bus approximately 38 minutes following the trip, the inspectors noted that restoration of the main condenser steam dump system was delayed for an additional four hours due to a design deficiency which caused the steam dump headers to fill with condensate. IR 98-06 identified a weakness in connection with the steam dump system. PER No. SQ980622PER presented a root cause evaluation of a May 19, 1998, water hammer event, a history of steam dump-related water hammer events dating to December 1980 and a corrective action plan which included a schedule for system modification and the distribution of an event summary to operations personnel.

The inspectors observed operations personnel preparing to place the steam dump system in service as vital bus power was being restored when the plant manager intervened, thereby preventing a likely water hammer event. The inspectors verified that following the trip, on November 19, 1998, the licensee revised procedure 0-SO-1-2, Steam Dump System, to provide operators with additional guidance regarding placing the steam dumps in service.

The inspectors observed two PORC meetings during the outage. The first meeting was held to evaluate a request for discretionary enforcement (see Section O1.3). The second meeting was held to review the plant trip report and to evaluate the acceptability of conditions for restart. The inspectors found the meetings to be conducted in a professional manner and the committee's examination of the issues presented to be thorough and appropriately conservative.

The inspectors observed that the post-trip review presented at PORC acknowledged the actuation of the steam generator (SG) safety valves but lacked a level of analysis to adequately explain how or why the malfunctioning ARVs challenged plant safety systems. The PORC appropriately recognized deficiencies in the post-trip analysis, that safety systems had been challenged but had functioned as designed. The PORC assessment and direction to the post trip review team was to revisit this issue for improvement.

The licensee initiated PER No. SQ981581PER to address the reactor trip, the failure of the 1-IV inverter, and system performance anomalies observed during and following the trip.

The inspectors initiated Inspection Followup Item (IFI) 50-327/98-10-01 to address the licensee's post-trip follow-up findings and inspector questions concerning management expectations, operator performance, procedural guidance, and the malfunctioning ARVs.

c. Conclusions

Operators and automatic plant systems controls maintained plant parameters within safety limits following a challenging Unit 1 reactor trip resulting from the loss of one channel of vital instrument power.

During the Unit 1 reactor trip, operators were unaware that the steam generator safety valves were cycling continuously for seventeen minutes due to a malfunction of the steam generator ARVs.

PORC thoroughly evaluated information presented by the Unit 1 reactor trip post-trip review team and appropriately challenged the thoroughness of the review.

O1.6 Failure of Unit 1 RCS Loop 1 Flow Indicators

a. Inspection Scope (71707)

The inspectors reviewed the licensee's course of action when the Unit 1 RCS Loop 1 flow indicators failed off scale high which prevented performance of a 12 hour TS required channel check and RCS total flow rate verification.

b. Observations and Findings

On November 20, 1998, at 5:49 a.m., Unit 1 operators observed that RCS Loop 1 flow indicators 1-FI-68-6A, 6B, & 6D were "pegged off scale high." The condition was discussed with control room management and an Engineering Assistance Request was initiated. TS 3.3.1.1, Reactor T .p System Instrumentation, required that a channel check be performed on the instruments once every shift (every 12 hours). T.S. 3.2.5, DNB Parameters, required a verification of RCS total flow rate once every 12 hours using the same three indicators. The last channel check and RCS total flow verification had been performed on November 19, 1998, at 10:00 p.m., with the next surveillances due by 10:00 a.m. on November 20. The channel check consisted of comparing the three indicators on Loop 1 to verify they were reading within 6% of each other. The RCS total flow verification consisted of summing all four loop flows and averaging the sum of the flows.

Since the surveillances could not be performed with the Loop 1 indicators pegged high, at 1:00 p.m. on November 20 (12 hours plus the 25% surveillance grace period), the licensee entered TS 4.0.3 for failure to perform a surveillance requirement, which they believed, under the circumstances, granted an additional 24 hours.

At 4:16 p.m. on November 20, operations began to reduce power and reached 35% at 6:28 p.m. At 6:20 p.m. on November 20, after concluding a review of data available from the plant integrated computer (S/G feed flow, RCS temperature, RCS leak rate, RCS pressure, and RCS Loop 1 flow) and confirming no changes in the actual plant parameters, the licensee concluded that the elevated reading on Loop 1 flow transmitters could not be explained by changes in plant cc nditions. The instruments were declared inoperable and the licensee entered TS 3.0.3. The licensee subsequently entered containment and tightened closed a leaking instrument line vent valve which restored the inoperable flow transmitters.

At 9:31 p.m. on November 20, a channel check was successfully completed on the Loop 1 flow indicators and Unit 1 exited the actions of TSs 3.0.3, 4.0.3, 3.3.1.1 and 3.2.5. The unit began a power increase and reached 100% power at 9:45 a.m. on November 21.

The inspectors were concerned that the licensee delayed entry into TS 3.0.3 for over 12 hours following identification that the Unit 1 RCS Loop 1 flow indicators had pegged high. With the flow indicators pegged high, two TS required surveillances were not performed within the required surveillance interval. The inspectors were also concerned with the licensee's decision to enter TS 4.0.3 for an RCS loop flow indicator deficiency/failure.

When the inspection period ended, the inspectors were reviewing the licensee's course of action and sequence of events related to the deficiency of the Unit 1 RCS Loop 1 flow indicators. This issue is identified as Unresolved Item (URI) 50-327/98-10-02.

c. Conclusions

One URI was identified for the potential failure to promptly enter TS action statements when Unit 1 RCS Loop 1 flow indicators pegged high.

O2 Operational Status of Facilities and Equipment

O2.1 Cold Weather Preparations

a. Inspection Scope (71714)

The inspectors evaluated the licensee's written cold weather program instructions for protection of safety-related systems against extreme cold.

b. Observations and Findings

The inspectors reviewed Periodic Instruction (PI) 0-PI-OPS-000-006.0, Freeze Protection, Revision 17, which identifies equipment and/or areas needing freeze protection, identifies means of protection, and provides requirements to ensure its operability during the months needed. The inspectors verified that the surveillance was being performed on a weekly basis as required. The inspectors also performed a walk down in several areas of the plant to verify that the licensee had taken action to ensure operable heat tracing or to provide compensatory freeze protection measures.

c. Conclusions

The licensee has implemented and maintained an adequate freeze protection program.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) Violation 50-327/98-04-01: Failure to perform TS surveillance 4.8.1.1.1.a. The inspectors verified the corrective actions described in the licensee's response letter, dated June 15, 1998, to be reasonable and complete. No similar problems were identified.

O8.2 (Closed) LER 50-328/98001: Turbine and reactor trips resulting from a failure of the 'B' phase main transformer sudden pressure relay. This event was discussed in IR 50-327, 328/98-08. No new issues were revealed by the LER.

O8.3 (Closed) LER 50-328/98002: Turbine and reactor trips resulting from a failure of the 'B' phase main transformer sudden pressure relay. This event was discussed in Section O1.4 of this report. No new issues regarding the sudden pressure relay failure were revealed by the LER.

The LER also discussed a mismatch between the control rod demand position indicator and the rod position information system (RPIS) which occurred during the unit startup following the trip. This was a previously identified problem and was caused by the nonlinear response of the RPIS. This issue was discussed in the closures of LER 50-327/95009, 96007, and 96-011 in IR 50-327, 328/96-17. No new issues were revealed by this LER concerning the nonlinear response of the RPIS.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (61726 & 62707)

Using inspection procedures 61726 and 62707, the inspectors conducted frequent reviews of ongoing maintenance and surveillance activities. The inspectors observed and/or reviewed all or portions of the following work activities and/or surveillances:

- SI-108.2 — Unit 2 Ice Condenser Intermediate Deck Door Inspection
- WO 98-007670 — Emergency Diesel Generator Winding Inspection (SQN-2-GEN-B-082-0002B-B)
- 0-SI-NUC-000-001.0 — Estimated Critical Conditions (Rev. 2)
- 0-SI-SXV-032-200.A — Train A Auxiliary Air Compressor Cooling Water Inlet Operability Test (Section XI) (Rev. 0)
- 0-PI-SFT-032-001.A — Train A Auxiliary Control Air Operability Test (Rev. 5)
- 0-PI-OPS-000-006.0 — Freeze Protection (Rev. 17)
- WR C414946 — Replace Bridge on 1-4 Vital Inverter
- 1-SI-OPS-082-024.B — 1B-B Diesel Generator 24 Hour Run and Load Reject (Rev. 0)
- WO 98-006873 — Place New Permanent Battery In Service for EDG 1A-A

b. Conclusions

The above maintenance and surveillance activities were completed in accordance with procedures and performed by knowledgeable personnel.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Unit 1 Unplanned Boron Dilution During U1C9 Outage

a. Inspection Scope (62707)

The inspectors reviewed the circumstances which resulted in an unplanned dilution of the Unit 1 RCS while the unit was in Mode 6.

b. Observations and Findings

On September 27, 1998, at 8:30 p.m., chemistry notified the Unit 1 control room that the RCS boron concentration was 2411 parts per million (ppm), which represented a 111 ppm change from the sample taken at 7:00 p.m. on September 26 (the minimum shutdown boron concentration required at the time was 2075 ppm). Operators held a crew briefing and subsequently stopped the primary water pump, since it was considered to be most likely supplying the dilution path. All dilution paths were investigated. Chemical and Volume Control System (CVCS) chemical mixing tank inlet valve,1-VLV-62-940, which had under gone maintenance during the refueling outage core empty period, was considered the most probable leakage path. A work request was initiated to verify and adjust the stop nuts on both the inlet and outlet valves (Grinnell diaphragm valves) to the chemical mixing tank. After backing off on the stop nuts for the valves, both valves were adjusted approximately a 3/4-turn in the closed direction. Operators then verified that the valves were closed and that there was no leakage through the valves. PER No. SQ981392PER was initiated to document the dilution event and to determine a root cause and corrective action plan.

The licensee determined that the root cause of the dilution event was misadjustment of the valve stops on the inlet and outlet valves, 1-VLV-62-940 and 1-VLV-62-944, for the chemical mixing tank. The likely cause for 1-VLV-62-940 leaking through was improper reassembly of the valve during U1C9 outage maintenance activities. The cause for 1-VLV-62-944 leaking through was indeterminate due to the numerous times that valve had been operated since the last maintenance performed on the valve.

Following the event, maintenance personnel conducted an extensive walk down of diaphragm valves with emphasis on valves designated as direct or indirect paths for dilution or boration. The results of that walk down indicated that valve stop misadjustments, which could allow leak through, did not appear to be an extensive problem, but that the general material condition of Grinnell valves needed improvement. Several corrective actions to prevent recurrence were initiated by PER No. SQ981392PER: including revising the diaphragm maintenance procedure to assure that the valve stops were adjusted correctly, complete a walk down on all valves on potential dilution flow paths in all modes and plant conditions (an extension of the walk down performed after the event), and conduct refresher training emphasizing that only mechanical maintenance personnel are to adjust valve stop nuts or do maintenance of any kind on manual valves.

The inspector reviewed procedure O-MI-MVV-000-029.0, Hand Operated Grinnell or Saunders Type Diaphragm Valve Maintenance, Revision 5, and discussed the procedure and maintenance technician valve training with the Mechanical Maintenance Manager. The inspector concluded that adequate procedural guidance existed to ensure proper adjustment of valve 1-VLV-62-940 following maintenance on the valve and that technicians failed to follow the procedure. Failure to follow procedure

O-MI-MVV-000-029.0, during maintenance activities related to diaphragm valve 1-VLV-62-940, resulted in a unplanned RCS boron dilution and is identified as a violation. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation (NCV) consistent with Section VII.B.1 of the NRC Enforcement Policy. This issue is identified as NCV 50-327/98-10-03.

The licensee concluded that a contributing factor to this event was the failure of operations to qualify, validate, and verify the RCS boron sample results. At 12:30 p.m. and 1:55 p.m. on September 27, 1998, the chemistry laboratory supervisor notified operators that boron concentration was decreasing. Operators discussed the fact that the reactor cavity had just been washed down which could have resulted in some dilution, but made no effort to verify that the quantity of water used in the wash down would cause the observed reduction in boron concentration. At 4:41 p.m., chemistry again notified operations that the boron concentration was decreasing, at which time operators directed that samples be taken every four hours. At 8:30 p.m., chemistry notified operations that the boron concentration had decreased to 2411 ppm. Operations then took prompt action to locate and isolate the possible dilution sources.

c. Conclusions

An NCV was identified for failure to follow procedure during maintenance activities on a diaphragm valve which resulted in an unplanned RCS boron dilution.

Operators failed to promptly validate Unit 1 RCS chemistry samples which resulted in a delay in identifying an ongoing dilution event.

The licensee conducted a thorough root cause evaluation of the Unit 1 dilution event and initiated corrective actions to address misadjustment of diaphragm valves.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) IFI 50-327/98-03-05: Follow licensee's review of emergency diesel generator degraded winding insulation. This issue initially involved the degradation of small sections of generator winding insulation on the 1B-B EDG. The licensee repaired the identified areas on the 1B-B EDG. The inspector verified that the licensee visually inspected the windings of the other three EDGs and that an imbalance test was performed on each EDG. Further evaluation by the licensee of the design of the 1B-B generator stator winding revealed that the original manufacturer used crimped connections for attachment of the stator winding leads, the internal coil group connections, and individual series coil connections. The crimped connections were the main contributor to the winding resistance imbalance. The licensee determined that the increased resistance caused by some of these crimped connections could increase localized heating at the affected crimps. Because these crimp connections were more heavily wrapped with insulation and the end turn area of the stator was exposed to the windage created by the rotor, the increased heating at connections was not expected to have a significant short term effect on the insulation system of the stator or the generator's capability.

The licensee subsequently performed an electrical inspection of EDGs 1B-B and 2B-B. Bridge readings were found to exceed procedure acceptance criteria. In addition, the stator windings resistance for EDGs 1B-B and 2B-B were found to have a 10% to 13% imbalance which was greater than the procedure acceptance criteria of 2%. EDGs 1A-A and 2A-A were not affected by the high resistance/phase imbalance phenomena. PER No. SQ980164PER was written to document the elevated bridge readings and determine corrective actions. The licensee's short term corrective actions included periodic measurement of stator winding resistance at increased intervals. Long term corrective actions included options which range from replacing the existing stator winding connections with brazed connections to replacing the existing stator windings with new stator winding having state of the art insulation system and brazed connections.

The inspectors provided the EDG bridge readings and imbalance data to NRR and requested assistance in evaluating the data. On the basis of the NRR review and the licensee's short and long-term actions, the inspectors concluded that the stator core windings for EDGs 1B-B and 2B-B were not experiencing resistance increases of a magnitude that could result in an unsatisfactory functional performance.

M8.2 <u>(Closed) IFI 50-328/98-08-01</u>: Follow-up on failure of 2A-A motor driven auxiliary feedwater (MDAFW) packing PER No. SQ981142PER. On August 27, 1998, the 2A-A MDAFW pump outboard packing failed following a Unit 2 trip. The licensee concluded that the failure occurred when the packing was extruded into the follower. The extrusion force required to cause this event was most probably caused by mis-adjustment of the packing. The licensee determined that a strong contributing cause was the marginal packing configuration which utilized die formed graphite packing without extrusion rings and the sensitivity of this packing to packing adjustments. The graphite packing was very sensitive to over torquing and required a precise adjustment. The licensee was unable to determine the origin of the misadjusted packing.

The licensee inspected the other five auxiliary feed water (AFW) pumps for a similar condition and determined that the packing followers were in the appropriate configuration and the packing leak-offs were as expected. New packing, a new packing sleeve, and a new gland follower were installed in the 2A-A pump. The gland follower temperature was monitored during initial operation and subsequent packing adjustments to verify the packing operated without overheating. A wax seal was installed on the packing follower nuts to determine unauthorized packing tightening. The licensee reviewed other packing types available for this application and subsequently installed "Rainsflow" packing on the 1A-A MDAFW during the U1C9 outage. The licensee intends to install "Rainsflow" packing on all AFW pumps during the next outage or as soon a practical.

III. <u>Engineering</u>

E8 Miscellaneous Engineering Issues (92903)

E8.1 <u>(Closed) IFI 50-328/97-18-03</u>: Followup on corrective action to resolve issue with Crosby relief valve degraded guide ring materials. This item had been opened pending further

NRC review of corrective actions to resolve the Crosby relief valve degraded guide ring material issue. The inspector reviewed the licensee's corrective actions which were documented in PER No. SQ972492PER. The licensee concluded that the failure of as-found set point testing was due to aging of the relief valves due to lack of periodic maintenance not specifically due to corrosion of the guide ring material. Work requests were initiated to refurbish all the ASME Section XI Class 2 and 3 valves. Relief valve maintenance instructions were reviewed to ensure they contain proper guidelines for valve refurbishment and adequately document as-found conditions related to aging. The inspector concluded that the corrective actions were reasonable and complete.

E8.2 (Closed) IFI 50-327/98-09-02: Review boron corrosion control program. This IFI was opened to conduct additional reviews to determine the adequacy of the licensee's boron corrosion control program following a decision to startup and operate Unit 1 with boric acid contamination on the exterior of the pressurizer.

Inspectors evaluated the licensee's decision to startup and operate Unit 1 with exterior boric acid contamination against licensee commitments in connection with NRC Generic Letter (GL) 88-05, Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants. GL 88-05 directs licensees to implement systematic measures to ensure that boric acid corrosion does not lead to degradation of the reactor coolant pressure boundary.

The inspectors noted that NRC Information Notice 86-108 (and supplements) commented that a primary defense against boric acid corrosion was to detect and stop leaks soon after they start and to promptly clean up any boric acid residue. The inspectors found no explicit requirement in either GL 88-05 or in the licensee's program to promptly clean up boric acid residue.

The engineering risk evaluation regarding the boric acid contamination on the exterior of the Unit 1 pressurizer was sound and conservative. The licensee's engineering requirements for control of borated water corrosion met the requirements of GL 88-05.

The inspectors concluded that the licensee's decision to restart and operate Unit 1 with boric acid contamination on the exterior of the pressurizer met the requirements of the licensee's boron corrosion control program and GL 88-05.

E8.3 (Closed) Violation 50-327, 328/98-06-03: Failure to perform an adequate safety evaluation prior to making modifications to the waste gas analyzer system. The inspector verified the corrective actions described in the licensee's response letter, dated July 27, 1998, to be reasonable and complete. No similar problems were identified.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on November 23, 1998. The licensee acknowledged the findings presented.

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

PARTIAL LIST OF PERSONS CONTACTED

Licensee

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

INSPECTION PROCEDURES USED

IP 61726: Surveillance Observations
IP 62707: Maintenance Observations
IP 71707: Plant Operations
IP 71714: Cold Weather Preparations
IP 92901: Followup - Operations
IP 92902: Followup - Maintenance
IP 92903: Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-327/98-10-01	IFI	Follow-up on post trip actions for unit 1 trip of November 9, 1998 (Section O1.5).
50-327/98-10-02	URI	Review licensee's actions related to failure of unit 1 RCS loop 1 flow indicators (Section O1.6).

50-327/98-10-03	NCV	Failure to follow diaphragm valve maintenance procedure (Section M2.1).

Closed

50-327/98-04-01	VIO	Failure to perform TS surveillance with EDG fuel oil transfer pump auto start disabled (Section O8.1).
50-328/98001	LER	Turbine and reactor trips resulting from failure of 'B' phase main transformer sudden pressure relay (Section O8.2).
50-328/98002	LER	Turbine and reactor trips resulting from failure of 'B' phase main transformer sudden pressure relay (Section O8.3).
50-327/98-03-05	IFI	Follow licensee's review of EDG degraded winding insulation (Section M8.1).
50-328/98-08-01	IFI	Follow-up on failure of 2A-A MDAFW packing PER No. SQ981142PER (Section M8.2).
50-328/97-18-03	IFI	Safety injection relief valve set point drift/degraded guide ring (Section E8.1).
50-327/98-09-02	IFI	Review boron corrosion control program (Section E8.2).
50-327,328/98-06-03	VIO	Failure to perform adequate safety evaluation prior to making modifications to the waste gas analyzer system (Section E8.3).
50-327/98-10-03	NCV	Failure to follow diaphragm valve maintenance procedure (Section M2.1).

LIST OF ACRONYMS USED

AFW - Auxiliary Feed Water
ARV - Atmosphere Relief Valve
CVCS Chemical and Volume Control System
DCN - Design Change Notice
EDG - Emergency Diesel Generator
GDC - General Design Criteria
GL - Generic Letter
IFI - Inspection Followup Item
IR - Inspection Report
LER - Licensee Event Report
MDAFW - Motor Driven Auxiliary Feed Water
NRC - Nuclear Regulatory Commission

NRR	-	Nuclear Reactor Regulation
PER	-	Problem Evaluation Report
PI	-	Periodic Instruction
PORC	-	Plant Operations Review Committee
ppm	-	Parts Per Million
psig	-	Pounds Per Square Inch-gauge
PWR	-	Pressurized Water Reactor
RCS	-	Reactor Coolant System
RPIS	-	Rod Position Indication System
SG	-	Steam Generator
SI	-	Surveillance Instruction
SO	-	System Operating Instruction
TACF	-	Temporary Alteration Change Form
TIA	-	Task Interface Agreement
TS	-	Technical Specifications
TVA	-	Tennessee Valley Authority
U1C9	-	Unit 1 Cycle 9
URI	-	Unresolved Item
Vac	-	Voltage-Alternating Current
VIO	-	Violation
WANO	-	World Association of Nuclear Operators
WO	-	Work Order