UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-327/94-07 and 50-328/94-07

Licensee: Tennessee Valley Authority
6N 38A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

Docket Nos.: 50-327 and 50-328 License Nos.: DPR-77 and DPR-79

Facility Name: Sequoyah Units 1 and 2

Inspection Conducted: February 6 through March 5, 1994

Lead Inspector: W.E. Holland 3-22-94
W. E. Holland, Senior Resident Inspector Date Signed

Inspectors: S. M. Shaeffer, Resident Inspector
R. D. Starkey, Resident Inspector
D. B. Forbes, Radiation Specialist

Approved by: Johns P. Jaudon 3/22/94
Johns P. Jaudon, Acting Deputy Director Date Signed
Division of Reacto. Projects

SUMMARY

Scope:

Routine resident inspection was conducted on site in the areas of plant operations, plant maintenance, plant surveillance, evaluation of licensee self-assessment capability, licensee event report closeout, and followup on previous inspection findings. During the performance of this inspection, the resident inspectors conducted several reviews of the licensee's backshift and weekend operations.

Results:

In the area of Maintenance, a weakness was identified regarding effective management communication of their expectations to lower levels of supervision and craft in control of breaches of fire protection barriers (paragraph 3.b.(2)).

In the area of Plant Support, an Inspector Followup Item was identified regarding review of licensee actions regarding undetected radioactive contamination being found on the Auxiliary Building roof (paragraph 3.e).

In the area of Engineering, a weakness was identified due to poor assumptions made concerning the effects of performance flow testing the 1B-B CCP. The testing activities did not adequately consider the net effect on pressurizer thermal transient limits as defined in Technical Specification 3.4.9.2. This resulted in the licensee exceeding the TS cooldown limits for the pressurizer (paragraph 4.a).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

O. Zeringue, Senior Vice President, Nuclear Operations
*K. Powers, Acting Site Vice President
J. Baumstark, Operations Manager
L. Bryant, Maintenance Manager
M. Burzynski, Nuclear Engineering Manager
*M. Cooper, Acting Maintenance Manager
D. Driscoll, Site Quality Assurance Manager
*T. Flippo, Site Support Manager
*J. Gates, Outage Manager
O. Hayes, Acting Operations Manager
C. Kent, Chemistry and Radiological Control Manager
*D. Lundy, Technical Support Manager
*M. Palmer, Radiation Protection Manager
*L. Poage, Site Audit and Assessment Manager
R. Rausch, Site Planning and Scheduling Manager
G. Rich, Chemistry Manager
J. Symonds, Acting Modifications Manager
*R. Shell, Site Licensing Manager
*M. Skarzinski, Technical Programs Manager
J. Smith, Regulatory Licensing Manager
*R. Thompson, Compliance Licensing Manager
*J. Walker, Operations Staff Manager
*J. Ward, Engineering and Modifications Manager
N. Welch, Operations Superintendent

NRC Employees

*P. Kellogg, Chief, DRP Section 4A

*Attended exit interview.

Other licensee employees contacted included control room operators, shift technical advisors, shift supervisors and other plant personnel.

Acronyms and initialisms used in this report are listed in the last paragraph.

On February 25, 1994, the licensee announced that Kenneth Powers, currently the Sequoyah Plant Manager had been named Sequoyah Acting Site Vice President, effective February 28, 1994. Mr. Powers was replacing Mr. Robert Fenech, who had accepted a position with Consumers Power Company in Michigan.

2. Plant Status

Unit 1 began the inspection period in MODE 5 (day 307 of the Cycle 6 refueling outage). During the inspection period, Unit 1 remained in MODE 5 with efforts continuing to correct restart deficiencies.

Unit 2 began the inspection operating at full power. The unit operated at power for the duration of the inspection period.

3. Operational Safety Verification (71707)

a. Daily Inspections

The inspectors conducted daily inspections in the following areas: control room staffing, access, and operator behavior; operator adherence to approved procedures, TS, and LCOs; examination of panels containing instrumentation and other reactor protection system elements to determine that required channels are operable; and review of control room operator logs, operating orders, plant deviation reports, tagout logs, temporary modification logs, and tags on components to verify compliance with approved procedures. The inspectors also routinely accompanied plant management on plant tours and observed the effectiveness of management's influence on activities being performed by plant personnel.

b. Weekly Inspections

The inspectors conducted weekly inspections in the following areas: operability verification of selected ESF systems by valve alignment, breaker positions, condition of equipment or component, and operability of instrumentation and support items essential to system actuation or performance. Plant tours were conducted which included observation of general plant/equipment conditions, fire protection and preventative measures, control of activities in progress, radiation protection controls, missile hazards, and plant housekeeping conditions/cleanliness.

(1) During the period, specific focus was directed to Unit 1 housekeeping in safety-related spaces. Several tours were conducted in Unit 1 safety-related pump rooms. During a back shift tour on February 15, 1994, the inspectors noted that the 1B-B CCP room had ground-water leakage to the point that floor coating residue was collecting beside the 1B-B pump. In addition, the pump skid had significant oil-water accumulation in the vicinity of the lube oil tank. The inspectors brought the above conditions to the attention of operations and other licensee management. Later in the period, the inspectors noted housekeeping improvement in Unit 1 plant areas. During the next inspection period, more focus will be placed on Unit 1 housekeeping as the unit makes preparations to return to power operation.

(2) During a plant tour on February 17, 1994, the inspectors noted that a fire door (A180) separating different trains of 480 volt safety-related MOVs electrical boards was breached open. The inspectors noted that the breach was established at this time in order to route an electrical cable through the door to power a portable air compressor located outside the #2 vital battery room (battery was being changed out in accordance with DCN 9007). Although the compressor was powered at the time of the inspection, no craft were using the equipment.

The inspectors questioned the licensee as to their process for maintaining breaches of fire barrier doors when it appeared that the breach was not necessary to accomplish specific work. Licensee fire protection personnel and management stated their expectations were for fire barriers to be secured when specific work was not in progress which required the barrier to be breached.

The inspectors had toured the plant on February 5, 1994, and noticed that the same door discussed above was open for support of the modification. At that time, no work was ongoing which required the breach. The inspectors brought the issue to the attention of operators. During a tour the next day, the inspectors noticed that the electrical connection was unplugged, and the fire door was closed.

The inspectors met with licensee modification and fire protection management on February 23, 1994, to discuss the above observations. All in the meeting agreed that breaching of fire protection barriers should be minimized. Also, whenever a work activity does not require a fire barrier to be breached, it should be secured. Management indicated that they would review communication of their expectations to determine if additional controls should be implemented.

Based on these observations and discussions, the inspectors concluded that licensee management expectations for breaches were appropriate. However, management had not effectively communicated their expectations to lower levels of supervision and craft so that breaches were properly controlled. This lack of effective communication to lower levels of plant supervision and craft was considered a weakness.

c. Biweekly Inspections

The inspectors conducted biweekly inspections in the following areas: verification review and walkdown of safety-related tagouts in effect; review of the sampling program (e.g., primary and secondary coolant samples, boric acid tank samples, plant liquid and gaseous samples); observation of control room shift turnover; review of implementation and use of the plant corrective action program; verification of selected portions of containment isolation lineups; and verification that notices to workers are posted as required by 10 CFR 19.

d. Other Inspection Activities

Inspection areas included the turbine building, diesel generator building, ERCW pumphouse, protected area yard, control room, vital 6.9 KV shutdown board rooms, 480 V breaker and battery rooms, and auxiliary building areas including all accessible safety-related pump and heat exchanger rooms. RCS leak rates were reviewed to ensure that detected or suspected leakage from the system was recorded, investigated, and evaluated, and that appropriate actions were taken, if required. RWPs were reviewed, and specific work activities were monitored to assure they were being accomplished per the RWPs. Selected radiation protection instruments were periodically checked, and equipment operability and calibration frequencies were verified.

e. Hot Particle Event

(1) Description of Event

On February 2, 1994, Region II was notified that on January 31, 1994, a worker alarmed the personnel contamination monitor upon exiting the RCA. Detailed surveys of the worker indicated a radioactive particle (Hot Particle) on the outside of the workers left pants leg. The particle activity was determined by the licensee to be .063 uCi. An isotopic analysis was performed which indicated the particle was primarily Cobalt 60 activation products.

Radcon HP personnel began surveys of the workers pathway; which, revealed another particle on the roof of the Auxiliary Building in the vicinity of where the worker was performing maintenance on a non-contaminated system. Additional follow-up surveys of the surrounding areas located ten additional particles for a total of twelve particles including the particle on the workers pants. All of the particles were confined to various levels of the Auxiliary Building roof. Five of the particles were located on the Auxiliary Building 764 level roof; five particles were located on the Auxiliary Building 784 level roof, and one particle was located on the Auxiliary Building Unit 2 wing roof. All of these roof levels are located adjacent to the Auxiliary Building ventilation exhaust duct. The particle with the highest activity (12 uCi) was located on the 764 level. Some of the particles found did not meet the licensee's criteria for a "Hot Particle" greater than 20,000 CPM. The licensee performed surveys of the ventilation plenum room and determined other particles exited the Auxiliary Building Ventilation System in this room. Based on work history involving hot particles and the isotopic analysis of the particles found, the licensee suspected previous work evolutions performed in the Fuel Transfer Canal as the primary source for the particles entering the Fuel Handling Area Ventilation System connected to the Auxiliary Building Ventilation System exhaust duct. The Fuel Handling Ventilation System takes suction from areas such as the Fuel transfer Canal, the Spent Fuel Pool, and the Waste Packaging Area. The inspector determined licensee design changes removed the filters from the Auxiliary Building ventilation system in 1978 prior to startup, as indicated in the FSAR.

(2) Inspector Followup

A Region II FRP inspector responded to this event during an inspection conducted February 2-7, 1994. During the inspection the inspector interviewed licensee personnel involved in the event including Site and Corporate personnel assigned to investigate the root causes of the event, reviewed the licensee's followup surveys, reviewed licensee procedures for control of hot particles, and inspected areas where the particles were found. The inspector also reviewed the PCR which noted the contamination to be a clothing contamination event resulting in a skin dose to the worker of .151 rem and a wholebody deep dose equivalent of .013 rem. Whole body counts on the worker determined no positive uptake had occurred.

The inspector reviewed and discussed with licensee representatives the immediate corrective actions performed as a result of this event to minimize reoccurrence. These licensee immediate corrective actions included the following:

- Surveys of all levels of the Auxiliary Building Roof to include downspouts.
- Surveys of various roof tops of buildings surrounding the Auxiliary Building.
- Surveys of the environment to include sediment samples, environmental air samples, and water and sediment samples of the run-off pond.
- Increase survey frequencies in the exhaust plenum room and on the various roof levels of the Auxiliary Building.

- Add a statement to ALARA planning reviews identifying transfer canal work as a potential source of particles and addressing radiological controls that may be needed for work being performed.

- Revise Radcon Management Directives and other applicable procedures to address Hot Particle Controls and Fuel Transfer Canal operations.

The inspector discussed with licensee representatives further evaluations to be performed and efforts to be made by the licensee to determine long term corrective actions to prevent hot particles from exiting the ventilation system to the Auxiliary Building roof. At the time of the inspection, the inspector found the licensee's efforts to be aggressive in surveying the roofs of other buildings, grounds surrounding the Auxiliary Building, and the performance of environmental followup surveys including the run-off pond and air samples to search for additional particles. The inspector informed the licensee that an Inspector Followup Item (327, 328/94-07-01) would be opened to review the licensee's actions regarding this event after the licensee had completed their final assessment and corrective actions.

f. Physical Security Program Inspections

In the course of the monthly activities, the inspectors included a review of the licensee's physical security program. The performance of various shifts of the security force was observed in the conduct of daily activities to include: protected and vital area access controls, searching of personnel and packages, escorting of visitors, badge issuance and retrieval, and patrols and compensatory posts. In addition, the inspectors observed protected area lighting, and protected and vital areas barrier integrity.

g. Licensee NRC Notifications

On February 23, 1994, the licensee made a four hour notification to the NRC as required by 10 CFR 50.72 regarding inadvertent ESF actuation of safety-related components. During restoration from the performance of 1-SI-SXV-032-029.0, CONTROL AIR CHECK VALVE TEST DURING COLD SHUTDOWN, Revision 0, non-essential air to containment was isolated, resulting in the closure of several containment isolation valves. The licensee restored air to the components and reopened the valves within the next 30 minutes.

The licensee initiated a PER to address this issue. An LER will be submitted by the licensee. The inspectors did not identify any immediate regulatory concerns during the initial review of this event. Additional review will be conducted as part of the closeout of the LER.

Within the areas inspected, one unresolved item was identified.

4. Maintenance Inspections (62703 & 42700)

During the reporting period, the inspectors reviewed maintenance activities to assure compliance with the appropriate procedures and requirements. Inspection areas included the following:

a. 1B-B Centrifugal Changing Pump Shaft Replacement

During the inspection period, the inspectors reviewed portions of PMT performed for the 1B-B CCP. The PMT was required for repair activities conducted during the previous inspection period which included shaft, bearings, and pump casing replacement. The CCP's shaft and bearings had been damaged due to reverse rotation caused by back leakage past a discharge check valve. These problems were previously discussed in inspection report 327, 328/94-04. During the current inspection period, PMT activities were performed on February 23, 1994, in accordance with a special test version of 1-SI-SFT-062-001.0 CHARGING PUMP INJECTION FLOW TEST, Revision 3 (PCF# 94-0010). The test was a special performance due to the activity being accomplished with the reactor head installed and a slight pressure (approximately 130 psig) established on the RCS to preclude degassing and RCS gas accumulation, a phenomenum also discussed in detail in Report 94-04. The purpose of the test was to develop a pump performance curve to compare with the pump's previous performance curve and to detact any effect on system balance. Full flow testing and system balancing for the charging system was previously performed after the unit was refueled in April of 1993 (prior to the shaft replacement).

The inspectors witnessed performance of the test and attended the pre-test briefing with operators and test personnel. The inspectors considered that the briefing was performed in a professional manner, and the test director adequately addressed questions posed by operations personnel. The testing was performed with the 1B-B CCP operating in the full injection mode and aligned to the RWST. Initial conditions prior to the performance were: RCS Tave was approximately 125 degrees F; one bank of pressurizer heaters were on with pressurizer temperature at approximately 347 degrees F; and pressurizer level at approximately 20 %. The test involved running the CCP to obtain the necessary performance data while filling the pressurizer from 20 percent to 80 percent.

The test procedure cautioned operators that the pressurizer temperature would cooldown and allowed operators to turn on pressurizer heaters to control the temperature within TS limits. However, during the test as the colder RCS entered the pressurizer, the total volume did not adequately mix, as was assumed by the test procedure to occur during the process. The change occurred in a very short period time such that operators could not have prevented the problem by placing more heaters in service. Pressurizer liquid temperature indication showed that a cooldown occurred of approximately 220 degrees F, whereas the LCO in TS 3.4.9.2 is less than 200 degree F cooldown in any hour period. The licensee identified this condition during the performance of 0-SI-SXX-068-127.0, RCS AND PRESSURIZER TEMPERATURE AND PRESSURE LIMITS, Revision 1, which was being performed due to the temperature change expected during the test.

The inspectors verified that the immediate ACTION requirements of TS 3.4.9.2 were met, including the return of the pressurizer temperature to within the appropriate limits. At the end of the inspection period, the licensee was continuing with their evaluation of the effect of the exceeded LCO. Initial engineering reviews indicated that no material/structural integrity problems resulted from the cooldown, other than the expenditure of one heatup/cooldown thermal cycle. Before the test, the number of thermal cycles on the pressurizer surge line was 29 with an upper limit of 200 cycles. The inspectors will review the licensee's final evaluation once completed under PER SQ940155.

The inspectors concluded that although the licensee anticipated that a change in the pressurizer temperature would occur during the test, poor assumptions were made regarding the amount of mixing which would occur. Had this issue been more thoroughly evaluated and anticipated, plant conditions could have been established prior to the test to prohibit a pressurizer temperature change greater than 200 degrees F from occurring.

The inspectors also compared the testing activities performed with the requirements of the applicable TS surveillance. The subject test was to ensure that the requirements of TS SR 4.5.2.h.2 and 4.5.3 would continue to be met in leu of the CCP shaft replacement and other activities. Specifically, TS SR 4.5.2.h requires, in part, that "each ECCS subsystem shall be demonstrated operable by performing a flow balance test during shutdown following completion of modifications to the ECCS subsystem that alter the subsystem flow characteristics". The licensee considered all work activities performed on the 1B-B CCP was maintenance and did not regard that the activities could or did alter the flow characteristics of the subsystem. This interpretation was the subject of a conference call involving the NRC Staff and the licensee on February 24, 1994. Based on the discussions, the NRC staff agreed that the flow characteristics of the ECCS subsystem were not affected by the repair activities; therefore, the TS was not applicable. It was also concluded that the testing performed by the licensee for the 1B-B CCP was acceptable.

The inspectors concluded that the performed PMT met the testing requirements specified in the applicable TS. However, the inspectors also concluded that poor assumptions were made by technical support concerning the effect of the testing activities on pressurizer thermal transient limits. This resulted in the licensee exceeding the TS cooldown LCO for the pressurizer. The inspectors identified this as a weakness.

b. Inspection of Instrument Air System

During this period, the inspectors reviewed portions of the plant instrument air system required to support the restart of Unit 1 (also known as the control air system - (System 32)). The inspectors focused this activity on the adequacy of corrective actions and preventative maintenance performed as a result of System 32 problems identified during the restart of Unit 2 in the later part of 1993. Some of these problems were previously discussed in detail in inspection report 327, 328/93-50 which included a failure of two air operated valves to open. These failures resulted in a total letdown isolation event which occurred on October 22, 1993. One of the air valve failures was due to diaphragm backing ring installation problem and the other due to a degraded air regulator. The incorrect diaphragm installation resulted in a shortened diaphragm life and subsequent failure during the event. The air regulator was degraded due to downstream air leakage causing high regulator cycling. A potential contributing root cause of the regulator problem was a lack of adequate preventative maintenance on air regulators in general. An additional event occurred on November 17, 1993, involving the failure of a Unit 2 charging system flow control valve. This event was previously discussed in inspection report 327, 328/93-52. The root causes of this failure involved an incorrectly sized air supply regulator and inadequate IDP controls.

During the current inspection period, the inspectors reviewed the corrective actions completed for these issues via PER 930730 and II SQ930701, performed air system component walkdowns, and reviewed the performed and future planned preventative maintenance for air operated valves and air regulators. The subjects reviewed included the following:

(1) PER 930730 was initiated to resolve discrepancies regarding regulator setpoint identification, verification, and control. Due to the above Unit 2 air system problems, a list of operationally significant air operated valves was developed, as described in the aforementioned inspection reports. This list was utilized in Unit 2 regulator and air system component inspections to provide a basis for Unit 2 continued operation. A similar list was developed for Unit 1 and was reviewed during the extended outage by the site engineering organization for regulator setpoint verification. Once completed, field walkdowns were made by Instrument and Mechanical Maintenance personnel to verify the correct setpoints were established. The field verification for the Unit 1 "operationally significant"

valve regulator list did not identify any major discrepancies similar to the original setpoint problems. Also included in the Unit 1 review process was a comparison of IDP, old calibration cards, and vendor pressure supply requirements. Several minor variations were identified and resolved.

(2) The inspectors reviewed the corrective actions taken for the previously identified system 32 problems as defined in IISQ930701. Specifically, actions were taken to prevent similar air regulator problems which occurred on Unit 2. The expected life of air regulators per vendor information ranged from 20 to 40 years, with the majority of the plants regulators being in service for approximately 15 years. However, the licensee concluded that some portion of the regulators would need replacement in the near future. To determine a replacement priority, the system engineer group expanded the "operationally significant" air operated valve list (known as Category A and B) to five categories of A, B, C, D, and E. Categories A through D could cause some range of plant transients whereas Category E would not place the unit in a condition which required a power reduction or a plant transient to mitigate the failure. Each system engineer reviewed and classified each air operated valve in his/her respective system for both units. The lists were utilized by the system engineers for the Unit 1 air valve walkdowns to identify not only regulator, but other air valve problems. Approximately 650 Unit 1 and common valves were categorized as A, B C, and D.

The total scope of the walkdowns for air regulators during the Unit 1 outage included approximately 1,000 regulators (including category E). By the end of the inspection period, the licensee had completed approximately 90 percent of the Category A, B, C, and D regulator walkdowns with a goal of 100 percent by restart. The remaining 10 percent of the walkdowns could not be performed until the equipment was placed back in service. The remaining inspections were identified on a punchlist by system to be completed prior to restart of the unit. The inspectors concluded that the reviews of each respective system's air regulators appeared to have been performed in a conservative manner and resulted in the replacement of numerous regulators. The licensee indicated that similar walkdowns would be performed on the Unit 2 AOV regulators during the next refueling outage.

(3) The inspectors also specifically reviewed the work activities accomplished on certain Unit 1 air operated valves. The valves reviewed were the Unit 1 valves similar to the Unit 2 valves which had the operational problems during the Unit 2 startup. The inspector verified the following activities were performed:

1-FCV-62-54, Excess Letdown Valve - Air regulator, valve diaphragm, and air solenoid replaced.

1-FCV-62-70, Normal Letdown Valve - Air regulator and valve diaphragm replaced.

1-FCV-62-93, CCP Discharge FCV - Air regulator replaced.

(4) The inspectors also reviewed with the licensee the status of establishing PMs for both air regulators and air diaphragms. Since the Unit 2 air system related operational events, the licensee completed a RCM study for the "operationally significant" category A and B air operated valves. The study resulted in the addition of preventative maintenance activities on nine valves during the Unit 1 outage. The inspectors concluded the RCM study for these specific valves was thorough and contained specific recommendations to improve AOV reliability. In addition, the study provided an initial database which could be utilized in the strategic AOV PM program.

(5) The inspectors also performed walkdowns of selected system 32 components in the auxiliary and Unit 1 containment buildings. The inspectors utilized the same air regulator inspection criteria established for the Unit 2 System 32 walkdowns. A leaking air regulator was identified in the upper containment. The regulator for 1-FCV-30-52, a containment isolation valve for the purge system, was leaking excessively through the weep hole. The inspectors were informed that this problem had been previously identified during the system engineer walkdowns and WR C198759 was initiated to correct the problem. No additional problems which could potentially affect the operability of the air system components inspected were identified.

The inspectors concluded from the review that the licensee had implemented appropriate corrective actions to support the Unit 1 restart regarding System 32 performance and reliability. System engineer reviews of their respective system's air regulators appeared to have been conservatively performed and recommended the replacement of numerous components. In addition, initial actions by the RCM group related to identifying and establishing routine PMs for AOV diaphragms and regulators were considered to be good. The RCM study of the category A and B AOVs was considered thorough and contained specific recommendations to improve AOV reliability. However, the inspectors also concluded that continued management support for the strategic development of this program was necessary to continue the formation and implementation of appropriate PMs for System 32 and other air operated components, including non-essential air regulators and diaphragms. The inspectors will monitor the performance of the control air system during the Unit 1 restart.

c. Repair of 1-FCV-061-0192, GLYCOL SUPPLY ISOLATION VALVE

Early in the period, the inspectors noted that the subject valve had been repaired and was identified as needing post maintenance testing. The inspectors obtained a copy of the work package (WO No. 93-06137-00) and the work request No. C214787. The work request stated that the valve had failed stroke time testing during performance of its surveillance test.

The inspectors reviewed the work package and determined that the valve was first worked in October of 1993. After that work, (cleaning of the valve stem), the valve again failed to stroke within the allowed stroke time (18.5 seconds). Work was re-commenced in November of 1993, involving insulation removal and reinstallation to assure that ice binding was not causing the problem. In December of 1993, system engineering was contacted to help in troubleshooting of the valve problem. Troubleshooting was accomplished in January of 1994. This troubleshooting identified the air solenoid or vent path from the valve to be the problem. The old air solenoid was replaced with a new one approximately January 20, 1994. Subsequent post maintenance testing determined the valve to be stroking within required times.

On February 16, 1993, the inspectors met with maintenance management and system engineering personnel to discuss the troubleshooting aspects of the maintenance activity. The inspectors concluded that troubleshooting did identify that the air solenoid valve was the probable cause of 1-FCV-061-0192 to not stroke within the required time. However, they also determined the following:

- Troubleshooting of the problem was not clearly described in the work package reviewed.

- A past similar problem with an SOV for the same valve could not be factored into the root cause evaluation because the SOV replaced was discarded prior to any SOV failure cause analysis being performed.

- The maintenance shop does not have a prescribed approach to troubleshoot problems of this nature. Also, the initial work order guidance of stem lubrication and retest was considered to be a poor practice.

The inspectors concluded that adequate corrective maintenance had been performed on the subject valve. However, the licensee's cause evaluation process for problems of this nature was undefined and left to the judgement of the planners or craft.

d. Repair of Boric Acid Transfer Pump 1B-B.

On February 27, 1994, the inspectors reviewed the work package (WO No. 94-01434-00) associated with repair of the subject pump. The pump had been identified as leaking excessively on February 1, 1994. The inspectors also had noticed leakage from this pump during plant tours in early February, 1994.

Craft maintenance notes in the work package stated the craft determined that heat trace had been installed outside the insulation on the pump. This was suspected to be part of the cause of the pump leaking problem. A problem evaluation report (SQ940141) was written to address this issue by the craft. The inspector concluded that the licensee corrective action process will adequately address this area.

The inspectors conducted additional reviews of past failures of boric acid transfer pump problems. They reviewed corrective actions for closeout of PER SQ930485 which was written in July of 1993. The PER identified a condition where the 1B-B boric acid transfer pump was experiencing a higher than expected failure rate for pump seals. The licensee's evaluation for this condition identified that an issue (89156, Upgrade Boric Acid Transfer Pump Mechanical Seals) had been opened to address the problem in 1989. However, the evaluation also stated the issue had been delayed until after implementation of the boron concentration reduction in this portion of the CVCS from 12 percent to 4 percent. The evaluation concluded this reduction should reduce the seal failures due to boron crystallizing on the seal face. The evaluation noted that 6 seal failures had occurred between introduction of a new seal in 1985 and the current failure in 1993. The evaluation also stated that seal failures occurred at various time intervals and the time in service prior to failure varied anywhere from three to 18 months during this period.

The inspectors met with licensee engineering personnel on March 2, 1994, to discuss the PER closeout evaluation. The inspectors questioned the licensee about the seal failure rates for the other three boric acid transfer pumps and any other information that was observed which could contribute to the failures. The inspectors were informed the failures for the other three pumps were similar to the 1B-B pump. Licensee engineering stated that they believe that the boric acid concentration reduction will significantly prolong pump seal life. The licensee has also projected the possibility of pump seal failures over the next six month period and made necessary preparations to address seal leakage in an expeditious manner during this period, if necessary.

The inspectors agreed with this conclusion and the licensee actions associated with ensuring that appropriate planning focus has been placed on potential pump seal failures between this inspection period and the Unit 2 Cycle 6 outage when the boric acid concentration reduction modification will be implemented. However, the inspectors were unable to determine why licensee actions to address frequent pump seal failures had not occurred sooner.

Within the areas inspected, no violations were identified.

5. Surveillance Inspections (61726 & 42700)

During the reporting period, the inspectors reviewed various surveillance activities to assure compliance with the appropriate procedures and requirements. The inspection included a review of the following procedures and observation of surveillance:

a. On February 15-16, 1994, the licensee performed 1-SI-OPS-082-026.B, Loss of Offsite Power With Safety Injection-D/G 1B-B Containment Isolation Test, Revision 4. The purpose of this SI was to verify the operability of Diesel Generator 1B-B, Safety Injection Signal, and ESF equipment. The inspectors reviewed SI-026B, monitored the EDG 1B-B 24 hour run, and observed the simulated loss of offsite power test from the control room.

   The inspectors noted that the licensee identified one test deficiency which occurred during the performance of section 6.1, Load Shedding, Test Sequence One, when the ERCW 1B-B shunt trip breaker failed to open as required. The breaker which failed had been installed under TACF No. 1-93-0052-201 and was of a different type than that specified by the design output drawing. This disparity had been evaluated by the licensee's Nuclear Engineering group and determined to be acceptable for operation until the correct breaker type could be procured. Following this failure the licensee replaced the failed breaker with the correct type breaker which had become available on site.

   In order to verify the operability of the replaced ERCW breaker and to meet the acceptance criteria of section 6.1 of SI-026.B, the licensee initiated a procedural change to section 6.8 of SI-026B, Simulated Loss Of Offsite Power, Test Sequence Eight, which tested the ability of the ERCW breaker to open on load shedding. The conditions under which the breaker was tested in section 6.8 were identical to those in section 6.1. During the performance of section 6.8, the breaker opened as required thus meeting the acceptance criterion. The licensee intends, however, to inspect the breaker again to ensure that it was not damaged as a result of the test. The licensee also is researching the failure history of the ERCW shunt trip breaker and plans to perform a failure analysis on the specific breaker which failed during this SI.

   The inspectors concluded that the licensee successfully met the acceptance criteria of SI-26.B and that the one identified test deficiency was adequately addressed.

b. Review of 1-SI-OPS-082-026.A, Loss of Offsite Power With Safety Injection-D/G 1A-A Containment Isolation Test, Revision 6.

During the later part of the period, the inspectors reviewed the results of the subject test. The purpose of this SI was to verify the operability of Diesel Generator 1A-A, Safety Injection Signal, and ESF equipment. The inspectors specifically focused on data recorded as part of the test.

On March 4, 1994, the inspectors discussed the test results with licensee test and engineering personnel. The inspectors specifically reviewed the test director logs, test deficiencies, and EDG 1A-A 24-hour test data with licensee test personnel. All data reviewed indicated that testing satisfied the surveillance requirements. However, one minor discrepancy was identified by the inspector which was immediately corrected by the licensee. The inspectors concluded that the test was accomplished in a satisfactory manner.

c. During the period, the inspectors reviewed the performance of 0-SI-SXX-068-127.0, RCS AND PRESSURIZER TEMPERATURE AND PRESSURE LIMITS, Revision 1. This SI was performed on February 23 to ensure compliance with RCS and pressurizer temperature and pressure limits as described in TS 3.4.9.2 and other applicable requirements. The performance of the SI was necessary based on plant conditions encountered during the performance of 1-SI-SFT-062-001.0 CHARGING PUMP INJECTION FLOW TEST, Revision 3 (PCF# 94-0010). During the CCP test performance, the SI identified that the pressurizer temperature cooldown LCO had been slightly exceeded. Other details of the CCP testing and the significance of the cooldown were previously discussed in paragraph 4.a. The inspectors reviewed the completed performance of 0-SI-SXX-068-127.0 and concluded that the SI adequately identified the pressurizer cooldown problem, verified other RCS limits were not challenged, and monitored the applicable parameters during recovery for the pressurizer temperature problem.

Within the areas inspected, no violations were identified.

6. Evaluation of Licensee Self-Assessment Capability (40500)

During this inspection period, selected reviews were conducted of the licensee's ongoing self-assessment programs in order to evaluate the effectiveness of these programs.

On February 9, 1994, the inspectors observed licensee activities in the Sequoyah Site Vice President principal staff weekly meeting. The meeting on this date specifically focused on the progress being made in several plant improvement areas. The primary vehicle used in the review process was the Sequoyah Management Assessment Review Team (SMART) report. This report is updated monthly so that senior management can monitor performance in areas such as plant performance, outage preparations, site improvement plan activities, and backlog reductions.

The reviews provided several indicators which management was continuing to focus on. Some of the items discussed in the backlog area with negative trends included hold orders and drawing deviations. In addition, additional management attention was being focused in several areas including work order/work requests, and other material condition areas. The inspectors considered that the management overview of Sequoyah backlog reviews was being accomplished as outlined in past meetings with the NRC. However, they also noticed that progress in several of the backlog areas was moving slower that originally projected. This area will be closely monitored by the inspectors during future inspections.

Within the areas inspected, no violations were identified.

7. Licensee Event Report Review (92700)

The inspectors reviewed the LERs listed below to ascertain whether NRC reporting requirements were being met and to evaluate initial adequacy of the corrective actions. The inspector's review also included followup on implementation of corrective action and/or review of licensee documentation that all required corrective action(s) were either complete or identified in the licensee's program for tracking of outstanding actions.

a. (Closed) LER 327/93-25, Failure to perform ASME Section XI Bolting Inspections. The issue involved a failure to perform ASME Section XI bolting inspections for second-stage reactor coolant pump assemblies following modification. Corrective actions included implementation of program controls to require a ASME Section XI program specialist to perform an impact review on design change packages to ensure that Section XI requirements are met. The inspectors verified that appropriate procedures were revised to include ASME Section XI repair/replacement guidance. Procedures reviewed included SURVEILLANCE INSTRUCTION 1-SI-SXI-000-114.0, Revision 0, ASME SECTION XI INSERVICE INSPECTION PROGRAM, UNIT 1; SURVEILLANCE INSTRUCTION 2-SI-SXI-000-114.0, Revision 0, ASME SECTION XI INSERVICE INSPECTION PROGRAM, UNIT 2; MI-10.2.3, Revision 4, REMOVAL, INSPECTION AND REPLACEMENT OF REACTOR COOLANT PUMP CARTRIDGE AND NUMBER 1 SEALS, Procedure Control Form 94-0077, and documentation for material suitability evaluations of seal component replacements that occurred during the Unit 1, Cycle 5 and Cycle 6 outages.

b. (Open) LER 327/93-26, Unqualified Coatings in Containment Exceed Design Basis Assumptions. The issue involved the licensee's identification of a significant amount of unqualified coating within the motor stand of the RCPs. The number 4 RCP is located within the containment sump ZOI and the identification of the additional unqualified coating caused the design-basis limit for unqualified coatings within the ZOI to be exceeded. URI 327, 328/93-42-02, Review of Licensee's Past Maintenance and Design Aspects of the Containment Sump, was identified to specifically address the RCP unqualified coating issue, as well as other protective coating concerns related to containment sump operability. Initial corrective actions for the unqualified coatings on the #4 RCP included the installation of debris/failed coating retaining screens on the RCP motor stand and access platforms to collect any coatings and prevents their transport to the containment sump. The NRC will evaluate the effectiveness of the screens and other corrective actions for the event during review of the URI. The URI is further addressed in paragraph 8 of this report.

The NRC and the licensee will continue to evaluate the effect of the additional unqualified coatings regarding operability of the containment sump. The licensee indicated that the LER may be revised once the reviews have been completed.

c. (Closed) LER 328/94-01, Two Inoperable Main Steam Isolation Valves (MSIVs) Caused Entry into Technical Specification (TS) Limiting Condition for Operation 3.0.3. The issue involved licensee identification of the subject condition due to generic concerns of MSIV binding at another nuclear plant. The licensee conducted special testing on Unit 2 during a forced outage and determined that binding was occurring on the MSIVs. This issue was discussed in inspection reports 327, 328/93-55 and 327, 328/94-04. Licensee corrective actions for this problem were inspected and docketed in those reports.

d. (Closed) LER 328/94-03, The Opening of a Cold Leg Accumulator Isolation Valve Results in Injection into Reactor Coolant System. The issue involved inappropriate operator actions which resulted in the subject event. The issue was discussed in inspection report 327, 328/94-04. A violation for ineffective corrective actions to preclude continuing configuration control problems was issued. Additional inspections will be conducted as part of the closeout of the violation.

Within the areas inspected, no violations were identified.

8. Action on Previous Inspection Findings (92701, 92702)

a. (Closed) IFI 327/93-16-01, Followup on Licensee Ev uations for Containment Electrical Penetration Leakage on Unit 1. The issue involved containment penetration test data taken early in the Unit 1 Cycle 6 refueling outage. Test data indicated that two electrical penetrations, X-164E and X-127E were leaking approximately 17 SCFH and 11.5 SCFH respectively. The subject penetrations are of an obsolete canister type and are not repairable. Based on the available information, the licensee decided not to replace the leaking penetrations prior to the next operational cycle. The combined identified leakage rates were below the allowable TS limit of 0.6 of the allowable leakage limit (approximately 135 SCFH). In addition, each individual penetration leak rate was below the ANSI N45.4 single penetration limit of 27 SCFH. However, based on the inspectors review of previous failure data, the inspectors concluded that their was a potential for continued degradation and possible exceeding of the TS leakage limits by the end of the next fuel cycle. In addition, the inspectors were concerned that no increased monitoring of the suspect penetrations was planned.

During the current followup inspection for Unit 1 restart from the U1C6 refueling outage, the inspectors reiterated the concern for continued degradation of the penetrations. The licensee provided the inspectors the results of a subsequent failure analysis performed to further evaluate the potential for continued degradation. This analysis verified assumptions that the penetration leakage points occurred throughout the cross-sectional area. In addition, the inspectors were informed that the subject penetrations were retested in November 1993. The leakage rate for X-127E remained the same; however, leakage for X-164E decreased to approximately 3.7 SCFH. However, considering the most recent test results, the inspectors continued to question the need for increased monitoring during operation in the next fuel cycle. The licensee performed an evaluation of available options to resolve the issue. The three options considered were: 1) Replace the penetrations prior to startup, 2) Leave the penetrations "as is", or 3) Startup with the known leakage and monitor during the operating cycle for any further degradation.

After considering these options, the licensee initially determined to leave the penetrations "as is" and not perform any "online" monitoring. This decision was based, in part, on the following:

- No available correlation to conclusively show continued degradation of the penetrations was inevitable. No information available from vendor on failure rates.
- Increased dose risk for "online" leakage monitoring (would be performed in the annulus).
- Long lead time for compatible penetration replacements.
- Current TS and ANSI N45.4 limits were not being exceeded.

However, late in the inspection period, the inspectors were informed that a method of monitoring the amount of nitrogen supplied to the penetrations was being developed. A nitrogen supply pressure of approximately 15 psig is supplied to the subject penetrations. The monitoring method would utilize existing nitrogen header pressure instrumentation to provide an indication if the known penetration leakage was increasing during

Unit 1 operation. The inspectors discussed these actions with licensee and NRC management. In that no regulatory limits were currently exceeded and that insufficient data were available to predict future penetration failures, the licensee decided to accept the risk of possibly exceeding leakage limits during the next operational cycle. Based on the improved results of the second performance of testing, the current acceptable leakage rates, and the licensee's proposed monitoring for changes in the leakage, the inspectors concluded that the licensee's decision was acceptable. The inspectors considered that the nitrogen monitoring will be useful in adding assurance of continued operability of the subject penetrations. The licensee is considering retesting the penetrations if a forced outage of sufficient duration presents itself (i.e. greater than one week). The inspectors will review the as-found leakage rates for the subject penetrations during the next performance of penetration leak rate testing.

The inspectors also reviewed the licensee's progress since May of 1993 for obtaining suitable replacements for the leaking penetrations. The licensee stated that if replacement penetrations had been available, the current leaking penetrations would have been replaced. Currently, the licensee is attempting to qualify suitable canister-type replacements for the subject penetrations. In addition, the licensee is continuing to review modular-type penetrations for future replacements. The inspectors noted that one of the explanations for not replacing the leaking penetrations during the current Unit 1 outage was that replacement penetrations were of long material lead time (approximately 26 weeks). The unit has remained in the extended outage since March 1993. The inspectors recognized that the licensee could not anticipate the prolonged extension of the outage; however, they also concluded that the licensee could better anticipate the need for replacement penetrations in the future.

b. (Closed) VIO 327, 328/93-23-03, Failure to Promptly Identify the Procedure Problem Associated with LER 327/92-21 During Corrective Action for LER 327/92-03. The issue involved licensee identification of inadequate corrective actions for an event resulting in inadequate configuration control of safety-related valves which resulted in a second similar event the following year. In their response to the violation dated August 17, 1993, the licensee stated that the continuing problem was caused by site personnel taking an inconsistent approach to the issue of containment integrity.

Corrective actions taken to preclude further repetition of the events included development of a site standard practice including criteria for and listing of locked valves in program, verification of FSAR, Table 6.2.4-1 regarding containment integrity valves, and revising the FSAR based on this review. The inspectors reviewed the licensee's corrective actions including SSP-12.64, LOCKED

VALVE PROGRAM, Revision 2 and the documentation supporting a change to the FSAR. Corrective actions appeared adequate.

c. (Closed) VIO 327, 328/93-33-04, Failure to perform TS Surveillance 4.9.1.2 Concerning Refueling Cavity Boron Concentrations. The issue involved a TS SI, which measures the boron concentration of the refueling cavity, not being performed within the TS allowable timeframe. Unit 1 was in MODE 6 and the refueling canal was flooded during this event. A boron analysis is required when the refueling canal is filled. In addition, a shield building Tritium analysis, which was also required with the refueling canal flooded, was not performed. The missed SIs occurred due to inadequate communication between Chemistry and Operations personnel. Specifically, the involved personnel used the terms "refueling canal" and "transfer canal" interchangeably. This resulted in Chemistry personnel believing that the refueling canal was drained and thus the required TS sampling not necessary. Immediate corrective actions were to sample the refueling canal and confirm the boron concentrations were within specification. Chemistry and Operations personnel were also counseled on the event and the importance of clear communications. The licensee determined that chemistry Surveillance Instructions could also be clarified to ensure that nomenclature for the refueling canal was consistent. The inspectors agreed with the root cause of the event as identified by the licensee and reviewed various Chemistry procedural enhancements. The inspectors concluded the licensee's corrective actions taken for this violation were adequate.

d. (Closed) VIO 327, 328/93-33-05, Failure to Follow the Requirements of SSP-8.2 for Timely Surveillance Instruction Reviews. The issue involved the NRCs identification that the licensee failed to meet the administrative requirements of SSP-8.2 SURVEILLANCE TEST PROGRAM, in that, the reviews for eight surveillance instruction packages were not accomplished within ten calendar days. The licensee identified the cause of the violation as ineffective management of work priorities. This resulted in outage-related activities commanding a higher priority than the required reviews of completed SIs. As a result of the violation, the licensee developed a new surveillance instruction review process which resulted in daily management attention during the current restart efforts. New SI review status information was placed in daily planning meeting information for management review. The licensee intends on reevaluating the frequency of the current reviews under the Sequoyah post restart plan. The inspectors monitored the licensee's review of completed SI's since the violation and implementation of the corrective action described above. They concluded that the corrective actions taken to date appear to have been effective.

e. (Closed) VIO 327/93-33-08, Design Change for Heat Trace for Unit 1 Emergency Boration Flowpath Outside of Plant Procedures. The issue involved modification of the heat trace circuitry on the

Unit 1 emergency boration flowpath being performed by a work request. The work request modification activity did not provide design controls as required by regulations.

The licensee responded to this violation by letter dated October 4, 1993. In their response, the licensee concluded that the cause of the violation was inappropriate management decision to install additional heat trace on the emergency boration line without the use of the temporary alteration control process. Licensee corrective actions for this issue included a review of lessons learned between the plant manager and appropriate other plant management, review of work orders that have been open greater than one year to ensure that other problems of this nature do not exist, and repair of the heat trace circuits affected by this problem.

The inspectors reviewed the licensee's corrective actions and verified that each had been accomplished. Specifically, the inspectors walked down the heat trace system for the safety-related portions of the CVCS with system engineers and verified that all circuits are installed as designed. In addition, the walkdown reviewed outstanding work requests on the system to assure that appropriate work was being accomplished to support Unit 1 restart.

f. (Closed) VIO 328/93-39-01, Failure to Properly Configure a Reactor Coolant Drain Tank Pump Discharge Throttle Valve in Accordance with System Operating Instructions. The issue involved a misconfiguration on the B RCDT pump discharge throttle valve 1-77-517B. The error occurred, in part, due to an operator utilizing unofficial tags with the incorrect valve-positioning information. In addition, the licensee identified a contributing cause being unclear clearance instructions. The inspectors reviewed the corrective actions taken for the violation which included removal of the unofficial tags, procedure enhancements, and counseling of involved personnel. The event was also presented to operators during a "stand-down" meeting to familiarize the Operations staff with this specific event. Other licensee actions to improve operations performance were ongoing throughout the inspection period in accordance with the Unit 1 restart effort. The inspectors concluded progress was being made in this area. However, continued management attention was warranted for additional improvements in operator performance. In addition to the above, the licensee's response also addressed additional information as requested in the letter which transmitted the Notice of Violation. Specifically, the NRC requested information concerning the use of unofficial throttle-valve configuration tags in order to assess the scope of this problem. The inspectors reviewed the information submitted in the violation response and concluded that the concerns were adequately addressed. The inspectors concluded that the corrective actions taken for the subject violation were adequate.

g. (Closed) VIO 328/93-39-02, Failure to Follow the Requirements of SSP-6.23 Regarding the Maintenance Troubleshooting Process. The issue involved Technical Support and Operations personnel performing troubleshooting outside the scope of activities described in a work package document. The specific activities involved investigation into an operational problem with the 2B RCDT pump on August 12, 1993. The licensee identified root cause was personnel error in adhering to the established scope of work in the troubleshooting procedure. A contributing factor was that the work package was not maintained at the work location as required. Corrective actions for the violation included clarifying the correct work practices with the involved personnel, issuance of a standing order to clearly define management's expectations in this area, and lessons learned training for systems engineers and their supervisors. The inspectors considered that the violation appeared to be isolated and concluded the corrective actions taken were adequate.

h. (Open) URI 327, 328/93-42-02, Review of Licensee's Past Maintenance and Design Aspects of the Containment Sump. The URI was identified to specifically address issues regarding protective coating concerns which could affect containment sump operability. Certain technical issues and assumptions described in the URI are currently being reviewed by the NRC staff for potential safety implications. The results of the reviews will be addressed in subsequent disposition of the URI. During the current inspection period, the inspectors reviewed the licensee's progress to date for resolution of the concerns discussed in the URI.

Specifically, the inspectors reviewed the licensee's corrective actions taken with respect to the restart of Unit 1 from the extended outage. Significant repairs were completed to the Unit 1 containment sump, upper containment liner, and other areas which were identified as having potential coating problems. These activities included, but not limited to the following:

- Replacement of damaged Carboline 305 topcoat on steel supports, components, etc. near the containment sump with Keeler Long 4500 qualified coating.

- Replacement of damaged topcoat on the fuel handling manipulator crane.

- Areas which had demonstrated delaminating Carboline 305 topcoat in the upper containment have had the topcoat removed (located on the upper containment liner above the ice condenser).

- Removed miscellaneous unqualified vendor coated items in the zone of influence or removed the unqualified coatings and recoated.

- Reduction of the total unqualified coating within the containment sump zone of influence to approximately 41 square feet (the new acceptable limit per Westinghouse evaluation being 84 square feet; whereas the previous limit was 56.5 square feet per WCAP 11534).

- Installation of retaining screens on the #4 RCP motor stand and motor stand openings to prevent unqualified internal coatings having a transport path to the containment sump (similar to the compensatory measure installed in Unit 2).

The inspectors also performed walkdowns of applicable areas of both upper and lower containments and visually verified the above activities were performed. An inspection was also performed within the containment sump zone of influence to ascertain whether the licensee's estimate and assumptions for the total amount of unqualified coatings were sound. The results of the inspections indicated that the licensee's estimate of approximately 41 square feet of unqualified coatings within the zone of influence appeared to be reasonable. It should be noted that this amount did not include the approximate 143 square feet of unqualified coating within the #4 RCP motor stand. According to the licensee, this amount, based on the addition of restriction screens, will not be transported to the sump, post-accident. The adequacy of this compensatory measure will be further evaluated by the NRC staff as part of the URI resolution. During the walkdown, a problem was identified regarding damaged debris screening installed on the drain from the #4 accumulator room which discharges into the sump zone of influence. The licensee initiated a restart work request (C197112) to correct the problem.

The inspectors concluded that since the identification of the issue during the Unit 2 restart effort, the licensee had improved the material condition of coatings in and around the Unit 1 containment sump and in other areas of the containment considerably. The amounts and material condition of the coatings in the ZOI appeared to be within the bounds of the limiting WCAP and were considered adequate to support Unit 1 restart. Currently, the Unit 2 containment sump and other associated areas have not been equitably repaired; however, they were considered acceptable for Unit 2 operation. Future inspections of the Unit 2 related areas will be performed to assess continued acceptable material conditions of the installed coatings. The inspectors concluded that the improvements identified above were, in part, the product of increased emphasis being placed on the coatings program within the Technical Programs and Performance Group. The program is implemented by SSP-9.50, PROTECTIVE COATINGS PROGRAM FOR SERVICE LEVEL I AND II AND CORROSIVE ENVIRONMENT APPLICATIONS. Continued performance in the area of containment coatings will be further evaluated during resolution of the URI.

Within the areas inspected, no violations were identified.

9. Exit Interview

The inspection scope and results were summarized on March 8, 1994 with those individuals identified by an asterisk in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings listed below. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Item Number	Description and Reference
IFI 327, 328/94-07-01	Review the licensee's actions regarding a personnel contamination event after completion of the licensee's final assessment and corrective actions.

Strengths and weaknesses summarized in the results paragraph were discussed in detail.

Licensee management was informed of the items closed in paragraphs 7 and 8.

10. List of Acronyms and Initialisms

ALARA - As Low As Reasonably Achievable
ANSI - American Nuclear Standards Institute
AOV - Air Operated Valve
ASME - American Society of Mechanical Engineers
CCP - Centrifugal Charging Pump
CFR - Code of Federal Regulations
CPM - Counts Per Minute
CVCS - Chemical and Volume Control System
DCN - Design Change Notice
DRP - Division of Reactor Projects
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
ERCW - Essential Raw Cooling Water
ESF - Engineered Safety Feature
FCV - Flow Control Valve
FRP - Facilities Radiation Protection
FSAR - Final Safety Analysis Report
IDP - Instrument Data Package
IFI - Inspector Followup Item
KV - Kilovolt
LCO - Limiting Condition for Operation
LER - Licensee Event Report
MOV - Motor Operated Valve
MSIV - Main Steam Isolation Valve
NRC - Nuclear Regulatory Commission
OCC - Operational Control Center
PCF - Procedure Control Form

PCR - Personal Contamination Report
PER - Problem Evaluation Report
PM - Preventative Maintenance
PMT - Post-maintenance Test
PSIG - Pounds Per Square Inch
RCDT - Reactor Coolant Drain Tank
RCM - Reliability Centered Maintenance
RCP - Reactor Coolant Pump
RCS - Reactor Coclant System
RPM - Revolutions Per Minute
RWP - Radiation Work Permit
RWST - Refueling Water Storage Tank
SCFH - Standard Cubic Feet per Hour
SI - Surveillance Instruction
SO - System Operations
SOI - System Operating Instruction
SOS - Shift Operating Supervisor
SOV - Solenoid Operated Valve
SR - Surveillance Requirement
SSP - Site Standard Practice
TACF - Temporary Alteration Control Form
TAVE - Average Temperature of the Reactor Coolant System
TS - Technical Specifications
uCi - Microcurie
URI - Unresolved Item
VIO - Violation
WO - Work Order
WR - Work Request
ZOI - Zone of Influence