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

Report Nos.: 50-327/92-06 and 50-328/92-06

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: March 1 through April 7, 1992

Lead Inspector: Paul J. Kellogg for 4/8/92
W. E. Holland, Senior Date Signed
Resident Inspector

Inspectors: S. M. Shaeffer, Resident Inspector
R. D. McWhorter, Resident Inspector

Approved by: Paul J. Kellogg 4/8/92
Paul J. Kellogg, Chief, Section 4A Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This 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 or weekend operations.

Results:

In the Maintenance/Surveillance functional area, an apparent violation was identified for failure to maintain the ice condenser doors operable for both units as required by TS 3.6.5.3 for an unknown period of time during operation in MODEs 1, 2, 3, and/or 4 (paragraphs 3.f(2), 3.f.(3), 3.f.(4) and 4.d).

In the Maintenance/Surveillance functional area, a non-cited violation was identified for failure to complete work as required by a DCN and its implementing workplan (paragraph 4.a).

In the Maintenance/Surveillance functional area, a continuing strength was identified with regard to the aggressive and well-coordinated planning of non-outage maintenance and surveillance activities associated with the facility's four Emergency Diesel Generators (paragraphs 4.c & 5.a).

In the Safety Assessment/Quality Verification functional area, a strength was identified with regard to ongoing audit, monitoring, and quality control activities in the site QA organization. The site QA organization performance in these areas was considered to be very good and provided plant management timely feedback of problem areas (paragraph 6.a).

In the Safety Assessment/Quality Verification functional area, a strength was identified with regard to the quality of LERs reviewed during this period. The format had been modified to include a better description of events. The format also included a sequence of occurrences which allowed for a better understanding of the event cause(s) (paragraph 6.c).

In the Maintenance/Surveillance functional area, a non-cited violation was identified for failure to follow the requirement of SSP-6.7, in that, required reviews of instrumentation non-conformance reports were not accomplished in a timely manner (paragraph 8.d).

A review of licensee performance was conducted for the first three weeks of the Unit 2 Cycle 5 outage (paragraph 3.g). Conclusions were as follows:

> Operations - Observed evolutions, including unit shutdown and fuel movement, appeared to be well coordinated. Operator monitoring of critical plant evolutions was effectively separated from ongoing outage activities. Management established aggressive and conservative policies to control outage work in order to minimize the risk to reactor decay heat removal systems, although communication problems were noted between management and shift supervision on plant lineups to support decay heat

removal systems. Operator performance during the Unit 1 shutdown and forced outage was also considered to be good.

Radiological Controls - Initial performance in this area appears to be improved for evolutions similar to those performed in the Unit 1 cycle 5 outage. Good ALARA planning has been exhibited on several dose-intensive jobs, with the total job dose being well within the dose estimate. The licensee's goal for Personnel Contamination Reports is being met, however; several Radiological Awareness Reports have shown that some poor radiological control practices were occurring. Cumulative exposure at the end of the inspection period was well under preplanned Radiological Controls outage goals.

Maintenance/Surveillance - Despite having to react to numerous major maintenance and surveillance activities in support of the unplanned Unit 1 outage, progression of planned work for the Unit 2 outage continued generally according to schedule.

Security - An improved accountability method for monitoring personnel access to containment was noted; however, also noted were examples of security personnel not being familiar with the use of containment access and material control procedures.

Engineering/Technical Support - Technical Support system engineer knowledge and identification of issues has been good.

Safety Assessment/Quality Verification - Management's intentions to promote accountability for outage activities at other worker levels has initially been viewed as effective. Management's decisions on the coordination of plant evolutions to minimize the risk to reactor decay heat removal systems were considered to be good practices.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*J. Wilson, Site Vice President
*R. Beecken, Plant Manager
*J. Brown, Modifications Project Control Engineer
*M. Cooper, Site Licensing Manager
*T. Flippo, Quality Assurance Manager
J. Gates, Technical Support Manager
C. Kent, Radiological Control Manager
*M. Lorek, Operations Superintendent
*P. Lydon, Operations Manager
*M. Palmer, Radiological Health Group Manager
*J. Proffitt, Compliance Licensing Engineer
J. Rausch, Modification Manager
*R. Rogers, Technical Support Manager
R. Salisbury, Communications Officer
J. Smith, Regulatory Licensing Manager
*R. Thompson, Compliance Licensing Manager
*P. Trudel, Nuclear Engineering Manager
*W. Vanosdale, Maintenance Program Manager

NRC Employees

B. Wilson, Chief, DRP Branch 4
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 March 3, 1992 the NRC Region II Section Chief, Paul J. Kellogg visited the Sequoyah Nuclear Plant. Mr. Kellogg attended the exit meeting for the previous inspection period, toured the plant with the inspectors, and met with licensee management to discuss current issues at the facility.

2. Plant Status

Unit 1 began the inspection period at full power. The unit operated at approximately full power until March 18 when a shutdown of Unit 1 was commenced and an unusual event was declared due to inoperable ice condenser doors (paragraph 4.d). The unit entered MODE 3 on the morning of March 19. After shutdown and during repairs to the ice condenser doors, a leak was identified on the feedwater nozzle for the number 3 SG (paragraph 4.e). Cooldown was then continued until MODE 5 was reached, and the unusual event was terminated on the morning of March 20. The unit was in MODE 5 with repairs to the feedwater lines continuing when the inspection period ended.

Unit 2 began the inspection period in coastdown at approximately 80 percent power. On March 13, the unit commenced a routine shutdown from approximately 70 percent power to begin the Cycle 5 refueling outage. The unit was taken off line, and the reactor shutdown that evening. The unit commenced a cooldown and entered MODE 5 (cold shutdown less than 200 °F) on the morning of March 15. The unit entered MODE 6 (reactor head detensioned/removed) on the morning of March 21. On March 26, the unit began core offload, and the offload was completed on March 29. At the end of the inspection period, the unit was in outage day 21 with all fuel removed from the vessel, and regularly scheduled outage maintenance activities in progress.

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.

(1) On March 13, 14, and 15, the inspectors monitored the shutdown of Unit 2, which was commencing the Cycle 5 refueling outage. The inspectors specifically focused on

operator activities and noted that operations evolutions were being well controlled. Organization of the control room activities appeared well planned in order to clearly separate senior operators supervising critical plant evolutions from those coordinating outage work. This arrangement continued throughout the inspection period.

(2) On March 27, the licensee informed the inspectors of a problem where operators allowed the temperature in the SFP to drop below minimum allowed values during the defueling of Unit 2. The AUOs assigned to monitor the SFP temperature failed to monitor temperature for several shifts due to the fact that the temperature indicator was inside a contaminated area set up for refueling support. AUOs erroneously categorized the SFP as non-operating equipment, and used a procedural allowance for extending the interval for monitoring non-operating equipment inside a contaminated area. This resulted in temperature drifting to 66 °F, two degrees below the operating limit of 68 °F, before corrective action could be taken.

The licensee immediately suspended defueling operations until SFP temperature was returned to the normal band. An evaluation was then performed by licensee reactor engineering on the effects of the low temperature on the design basis for the SFP. The licensee concluded that there was an adequate margin in both the design and actual conditions of the SFP to ensure that the TS design criteria for maintaining K-eff less than 0.95 was not exceeded. Licensee management took additional corrective action with operations personnel to review the incident and communicate expectations for the conduct of shiftly rounds. Inspectors considered licensee corrective actions to be adequate, but that the incident was another problem identifying the need for increased focus by the licensee in the area of AUO duties and responsibilities. The licensee is continuing to implement a long term program to improve AUO performance.

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.

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; Unit 1 and 2 containments; vital 6.9 kv shutdown board rooms, 480 v breaker and battery rooms; 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. The inspectors routinely independently calculated RCS leak rates using the NRC RCS leak rate computer program specifically formatted for Sequoyah. 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.

On March 27, the inspectors monitored activities related to the start of fuel offload for Unit 2. The offload appeared to be well coordinated, with the SRO in charge of fuel handling aggressively supervising the contractor personnel actually conducting the fuel handling evolutions. Inspectors reviewed the status of fuel handling interlocks and found that in the two cases where interlocks had been bypassed due to material failures, adequate compensating actions had been put in place.

e. 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.

On March 19 and 21, during tours of the control points for entry into the Unit 1 and 2 containments during MODES 3 and 5 respectively, the inspectors noted that the security department had implemented a new process for control of personnel entering containment. The process involved collection of the vital access badges for those persons entering containment at the control point. The badges were returned to personnel at the time they exited the containment control point. This appeared to the inspectors to be a improved accountability method for monitoring personnel access to the containment.

However, during Unit 1 containment entries made by the inspectors, the inspectors noted that security personnel were not fully familiar with the use of containment access procedures. The involved personnel were generally unfamiliar with how to properly fill out the documentation necessary for the containment entry. A separate problem was noted with material control verifications being improperly performed for personnel exiting Unit 1 containment while in MODE 3. These items were discussed with the licensee's security management. The inspector concluded that this may reflect an inadequacy in security guard training on control of personnel access to containment and material control procedures.

f. Licensee NRC Notifications

(1) On March 7, 1992, the licensee made a call to the NRC as required by 10 CFR 50.72 concerning an inadvertent ESF actuation (CVI) on Unit 1, which occurred during a post maintenance testing (PMT) activity on radiation monitor 2-RM-90-112A. Unit 1 was operating at full power during the event. During the performance of the PMT on 2-RM-90-112A (Unit 2 upper containment radiation monitor), instrument maintenance personnel mistakenly conducted a step of the PMT evolution on the Unit 1 upper containment radiation monitor (1-RM-90-112A), which resulted in a Unit 1 CVI. The licensee

verified that all systems functioned as designed during the event and immediately reset the ESF function. The licensee conducted an incident investigation for this event which is discussed in paragraph 6.f. The licensee will submit an LER for this event.

(2) On March 17, 1992 the licensee made a call to the NRC as required by 10 CFR 50.72 concerning the Unit 2 ice condenser having been found to be degraded while in a shutdown condition. With the unit in MODE 5 following shutdown for the cycle 5 outage, routine inspections of the ice condenser revealed that 27 of the 48 ice condenser doors required excessive force to open. Fifteen of the doors appeared to be severely restrained. This force would be above the maximum torque required by TS 3.6.5.3. Licensee inspections in the area revealed that the inner ice condenser concrete floor pad appeared raised up to one inch in various bays. The raised floor had pushed up metal flashing at the bottom of the doors, causing it to interfere with door operation. Additionally, cracks and buckling of the floor was observed in the vicinity of fixed steel columns. Additional inspections by the licensee and resident inspectors in the Unit 2 ice condenser determined that some of the pads appeared to be raised up to two inches. Information on licensee investigations and subsequent action is contained in paragraph 4.d. The licensee will submit an LER for this event.

(3) On March 18, 1992 the licensee made a call to the NRC as required by 10 CFR 50.72 concerning Unit 1 potentially being outside of its design basis. Following the identification of problems in the Unit 2 ice condenser doors, Unit 1 was inspected while in MODE 1 at 100% power, and similar ice condenser problems were noted. Eleven of 48 ice condenser doors could not be opened without excessive force. Licensee inspections revealed that the floor of the Unit 1 ice condenser was raised in several of the bays with cracks similar to those found in the Unit 2 ice condenser. The licensee entered TS LCO 3.6.5.3, and later began a unit shutdown (paragraph 3.f.(4)). Additional information on licensee investigations and subsequent action is contained in paragraph 4.d. The licensee will submit an LER for this event.

(4) On March 18, 1992 the licensee made a call to the NRC as required by 10 CFR 50.72 concerning the declaration of an

unusual event. The unusual event was d clared in accordance with the licensee's emergency plan due to a decision to shut down Unit 1 based on the inability to meet TS requirements for operable ice condenser doors. Licensee management considered the degraded condition of the Unit 2 ice condenser (paragraph 3.f.(3)), and decided to shutdown based on the magnitude of the problems which required entry into TS LCO 3.6.5.3. The management decision to immediately shutdown Unit 1 was considered conservative.

The Unit 1 s' tdown commenced at 10:10 p.m., and the licensee entered MODE 3 at 2:47 a.m. on March 19. Upon entering Unit 1 containment, a leak on the feedwater nozzle for the number 3 SG of approximately 5 gpm was noted. The licensee then proceeded with coc down of the unit, and MODE 5 was entered at 2:05 a.m. on March 20. At that time, the unusual event was terminated. Additional information on licensee investigations and subsequent action is contained in paragraphs 4.d and 4.e. The licensee will submit an LER for this event.

g. Outage Functional Area Reviews

During this inspection period, the inspectors focused on review of licensee performance during the first three weeks of the Unit 2 Cycle 5 refueling outage in several functional areas. The following initial conclusions were reached during this period:

Operations - Control of the Unit 2 shutdown for the scheduled refueling outage was noted to be good. Observed evolutions, including unit shutdown and fuel movement appeared to be well coordinated. Operator monitoring of critical plant evolutions was effectively separated from ongoing outage activities. Management established aggressive and conservative policies to control outage work in order to minimize the risk to reactor decay heat removal systems. However, twice during decay heat removal operations, problems were noted which indicated that management's expectations were not effectively communicated to shift supervision. No specific operational requirements were violated. Operator performance during the shutdown and forced outage of Unit 1 was also considered to be good.

Radiological Controls - Initial performance in this area appeared to be improved for evolutions similar to those performed during the Unit 1 cycle 5 outage. RCS chemical shocks early in the outage appear to have been effective in reducing the source term. Good ALARA planning has been exhibited on several dose-intensive jobs, with the total job dose being well within estimates. The licensee's goal for PCRs was being met, however; several RARs have shown that some poor radiological control practices were occurring. Improved contamination zone exit points have been established allowing workers to proceed through more numerous and larger stepoff areas. Cumulative exposures by the end of the inspection period were well under preplanned Radiological Controls outage goals.

Maintenance/Surveillance - Despite having to react to numerous major maintenance and surveillance activities during the unplanned Unit 1 outage, progression of planned work for the Unit 2 outage continued generally according to schedule. At the end of the inspection period, outage activities were generally being accomplished on schedule.

Security - Implementation of an improved accountability method for monitoring personnel access to the containment was noted. However, the inspectors also noted that security personnel were not fully familiar with the use of containment access and material control procedures.

Engineering/Technical Support - Technical Support system engineer knowledge and identification of issues has been good. This has particularly evident by the strong involvement of system engineers in investigating, tracking, and resolving problems in the ice condensers and RCS level instrumentation.

Safety Assessment/Quality Verification - Management involvement in outage scheduling continued to focus on safety with reduced inventory operation being scheduled after core offload. Management oversight of outage activities has changed slightly from the Unit 1 cycle 5 outage. Senior plant managers are now briefed on outage activities after the 6:00 a.m. line management outage meeting. Management's intentions to promote accountability for outage activities at the level of other workers has initially been viewed by the inspectors as effective. Management's decisions on the coordination of plant evolutions to minimize the risk to reactor decay heat removal systems were considered to be very good.

Within the areas inspected, no violations were 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. On March 3, 1992, the inspectors received response from the licensee to questions on missing handswitch panels in the auxiliary shutdown control room. The inspectors had discussed a concern, that, with certain handswitch panels not installed, the panel fire detection system (ionization detectors) may be bypassed and unable to provide full detection capabilities. The licensee evaluated the condition and concluded that the missing handswitches or covers did not prevent the panel fire detection from performing its intended function. During the review of work associated with the subject panels, it was determined that WP MO2644A-02, had been closed on October 31, 1990. However, the areas on the panels were not covered as required by the work document. In addition, the DCN (M02644A) had also required the installation of filler plates for the panel areas where the handswitches had been removed. Once identified to the licensee, PER number SQPER92007 was written to address the problem and corrective actions. By the end of the inspection period, the licensee had initiated adequate corrective actions for the auxiliary control room panels. The inspectors reviewed AI-19 (Part VI), Modifications: Permanent Design Change Control Program, Revision 12, with regard to the failure to perform the work required by the DCN and workplan. Section 6.6.1.1 requires, in part, that the cognizant section perform the work per the workplan, in order to implement the DCN. The failure to adequately complete the work activities is identified as a non-cited violation for failure to follow the requirements of AI-19 (327, 328/92-06-01). The violation is not being cited because the criteria specified in Section V.A of the Enforcement Policy were satisfied.

b. On March 10 and 11, 1992, the inspectors monitored activities related to maintenance performed on the OB-1 component cooling system (CCS) heat exchanger. The activities were performed per O-MI-MRR-070-611.0, COMPONENT COOLING SYSTEM HEAT EXCHANGER MAINTENANCE, Revision 1 and WR C077577. The work included disassembly, cleaning, and inspection of the plate heat exchanger internals. The inspector witnessed portions of the work in progress which included unit disassembly and hydrolazing of the internal plates. The ERCW side of the heat exchanger had a buildup of black river slime, several millimeters thick, which was washed down utilizing a high pressure water spray. The CCS side of the heat exchanger was relatively free of any significant fouling. The work documentation, both at the work site and upon final completion, was reviewed and found to be accurate with no discrepancies noted by the inspectors. During initial inspection of the ERCW side of the heat exchanger, several gallons of small, asiatic clams were found near the bottom of the plates. No live clams were found. Evaluation of the clam condition by the system engineer determined that they did not significantly affect the required ERCW flow, as they were located in a deadheaded region of the heat exchanger. PER number SQPER920077 was initiated to document and track corrective actions for the clam intrusion. The ERCW strainers and chemical treatment program should have prevented any fouling from asiatic clams as detailed in the FSAR. The inspectors will continue to monitor corrective actions for the PER in future inspections.

c. On March 11, inspectors observed two maintenance activities in conjunction with a planned monthly outage of the 1B-B EDG.

(1) WR-C014574, DCN-8138A, Replacement/Relocation of 1B-B EDG Starting Air Reducer Valves. This work was being performed by the Modifications Group to improve the performance of EDG starting air reducers. This was the third EDG to have the modification installed. Inspectors observed the verification of work completion by QA personnel, including non-destructive test of weld joints and material verifications. No deficiencies were noted. Additionally, inspectors reviewed the entire modification work package present at the job site. The package was found to be complete and well organized for the use of personnel performing the modification.

(2) WR-C06732, Rework of 1B-B EDG Control Power Battery Cell Connections. Inspectors observed the torquing of cell connectors following cleaning, and the performance of post maintenance resistance checks on the connections. This work was performed by Electrical Maintenance Group personnel, with QA personnel involved in the verification of critical steps. No deficiencies were noted.

d. From March 17 through the end of the inspection period, inspectors monitored licensee maintenance activities associated with the resolution of problems discovered in the ice condenser of both units (paragraph 3.f.(4)).

On March 17, inspectors accompanied licensee personnel and entered the Unit 2 lower ice condenser. The inspectors confirmed the licensee's findings of significant jamming of the lower inlet doors due to interference from the flashing on the lower edge. The flashing had been displaced upward by the concrete wear pad which forms the floor of each bay. Cracks in the pad were noticed in numerous bays up to one-half inch horizontal and two inches vertical displacement on each side of the crack. The cracks encircled the fixed columns running through the slabs, and there were visible height differences between adjacent slabs at their expansion joints. In numerous bays, slabs had risen approximately one inch so as to press up against the lower turning vane of the ice condenser lower structure.

On March 18, following the Unit 1 shutdown due to identification of similar ice condenser problems, inspectors entered the Unit 1 ice condenser. The inspectors confirmed the licensee's findings of degradation of the floors of some bays to a lesser degree than in Unit 2. However, cracks in the slab were still present in several bays, with up to approximately one inch of height difference between each side of the crack, and some slabs were touching the turning vanes.

At the time of the inspectors' entry into Unit 1, the licensee had completed a temporary modification to each of the lower inlet doors to remove a portion of the flashing from under the doors. The modification was verified by post-maintenance testing to have returned the doors to a fully operational condition. The inspectors examined the modifications and found that in numerous bays, the removal of the flashing had allowed the insulation pads underneath to be freed for movement. The insulation consisted of plastic bags (approximately 12"x 8"x 4") filled with yellow fiberglass insulation. In most of the bays, the bags were able to be removed easily by hand. The inspectors expressed concerns to the licensee that during an accident condition, flow thorough the doors could dislodge the bags allowing them to migrate to the ice condenser drains or the containment sump. After review, the licensee decided to perform an additional modification to remove the insulation bags and replace them with foam insulation strips glued to the polar crane wall.

On March 23, NRC Region II issued a Confirmation of Action Letter (CAL) to the licensee requesting TVA complete several actions related to the ice condenser problems prior to the restart of Unit 1. These actions included root cause analysis of the event, safety evaluations to analyze the effects on all the affected safety systems, structures and components, and short and long term corrective actions. The licensee addressed the CAL issues in a letter to the NRC dated March 27, 1992, and presented their actions on these issues in a meeting with the NRC on April 3. Licensee actions were being reviewed by the inspectors when the inspection period ended.

The licensee analyzed the cause and effect for the ice condenser floor movement. Analysis included floor surveys and mapping, boroscope surveys through gaps in the bay drains, and inspections of the underside of the structural concrete and containment liner. Additionally, as found door opening torque values were recorded for the Unit 2 doors to bound the effects of the degradation. Due to initial efforts to restore ice condenser operability in MODE 3, Unit 1 doors were modified prior to recording any quantitative as found door opening torque values. Subsequent inspections revealed that sealant was missing from various areas around the floor slab. The licensee postulated that the most probable cause of the floor slab movement was repeated leakage of defrost water through these gaps into the area under the floor slab. This water then froze and pushed the slabs upward to jamb the doors.

In order to allow for the restart of Unit 1, the licensee's safety assessment included actions to frequently monitor for additional wear slab movement during power operation in order to prevent an undetected recurrence of the door jamming. To support monitoring in conjunction with the facility's ALARA program, the licensee designed and installed an electronic position indicating system to monitor and display slab displacement. This system was able to be read from outside containment. The licensee also established a procedure for monitoring and recording of data, and to require containment entry and inspection if significant wear slab movement was detected. At the end of the inspection period, the licensee reported that no movement was detected during the two weeks since monitoring began shortly after the Unit 1 shutdown. The licensee was continuing to formulate a permanent modification to Unit 2 to be completed prior to restart from the refueling outage.

Additional detail on the facility's analysis and evaluation of the ice condensers for both units is also contained in Inspection Report 327, 328/92-10.

The inspectors reviewed licensee compliance with TS 3.6.5.3 in relation to the subject event. This specification requires, in part, that the ice condenser inlet doors be operable when in MODES 1, 2, 3, and 4. Contrary to the above, on March 17 and 18, numerous ice condenser doors on both units were discovered to require forces in excess of technical specification required limits to open. This condition may have existed for extended periods of time coincident with both units operating in MODES 1 through 4. Failure to maintain the ice condenser doors operable as required by TS 3.6.5.3 is identified as an apparent violation (327, 328/91-06-02).

e. From March 18 through the end of the inspection period, inspectors monitored licensee activities associated with the discovery and repair of a crack in a weld on the feedwater line transition piece for the Unit 1, number 3 SG. The crack was identified when a feedwater leak occurred shortly after Unit 1 entered MODE 3 for repairs to the ice condenser. The crack required cooldown of the plant to MODE 5 to complete repairs and evaluate the other feedwater lines in both units for similar problems.

The licensee performed radiographic testing on the weld prior to removal of the cracked section. Results showed a seven inch circumferential crack at the root of the nozzle to transition piece weld, perpendicularly propagating through the weld to a two inch crack at the surface. Radiography was also performed on the other three Unit 1 feedwater lines, and it was found that a Unit 1 number 4 SG feedwater line weld was also defective. The licensee then examined Unit 2 and discovered that feedwater line welds on the Unit 2 number 1, 3, and 4 SGs were also defective. The licensee then began work to replace the feedwater line transition pieces, elbows and welds on all feedwater lines on both units.

Additional detail on the analysis and evaluation of the defects in the feedwater line transition welds for both units, corrective actions, and the facility's non-destructive testing program are contained in Inspection Report 327, 328/92-09.

Within the areas inspected, one apparent and one non-cited violation 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. Inspection areas included the following:

a. On March 11, inspectors observed three surveillance activities in conjunction with a planned monthly outage of the 1B-B EDG.

(1) MI-13.1.10, SETPOINT VERIFICATION AND CALIBRATION FOR TIME DELAY RELAYS ASSOCIATED WITH DIESEL GENERATOR LOGIC, Revision 0. Inspectors observed the lifting and landing of leads, installation of test equipment, and actual response testing of the time delays associated with EDG control relays. This work was performed by electrical maintenance personnel, with QA personnel verifying critical steps. No deficiencies were noted. Inspectors reviewed the completed surveillance documentation and found no deficiencies.

(2) SI-166.36.5, DIESEL STARTING AIR VALVE TEST FOR DG SET 1B-B, TIME FRAME A, Revision 0. This surveillance was performed as a post-maintenance test for the modification of the 1B-B EDG starting air reducer. Inspectors observed the releasing of the EDG clearance, valve lineups, installation of test gauges, starting of the EDG, and recording of test data. No deficiencies were noted. Inspectors reviewed the completed surveillance documentation and found no deficiencies.

(3) SI-OPS-082-007-B, ELECTRICAL POWER SYSTEM DIESEL GENERATOR 1B-B, Revision 1. This surveillance was performed in conjunction with SI-166.36.5 for the monthly test of the 1B-B EDG. Inspectors reviewed test preparations and the completed surveillance documentation and found no deficiencies.

One minor problem occurred during other work being performed on the 1B-B EDG. After noting the presence of an unexpected low oil pressure alarm, the AUO found that the 1B2 oil soakback pump was off. The pump was restarted by the AUO, and the alarm cleared. Licensee investigations failed to reveal a cause for the pump trip, and no additional problems were identified.

Inspectors observed that the maintenance activities (paragraph 4.c) and the surveillances on the 1B-B EDG were well coordinated. A supervisor was present throughout the work to ensure that the EDG was returned to service as soon as possible. He actively pursued the completion of all EDG work without delays or interference between the various organizations involved in the work. This reflected an appropriate concern for the need to ensure that the safety-related EDG was out of service for the minimum possible time. This attention has been observed by inspectors in the past, and appears common practice for the plant for weekly outages of all four EDGs. This routine aggressive planning and coordination of EDG maintenance and surveillance activities was considered to be a continuing facility strength by inspectors.

b. On March 15, the inspectors monitored preparations for the performance of 2-SI-OPS-082-026.A, LOSS OF OFFSITE POWER WITH SAFETY INJECTION - DG 2A-A CONTAINMENT ISOLATION TEST, Revision 1. The purpose of the test was to verify the operability of the 2A-A EDG, Safety Injection Signal, and Engineered Safety Feature equipment. The inspectors also reviewed the portions of the completed test procedure prior to final licensee review of results. The inspectors noted that test director control was considered good and that only two component failures were experienced during testing. However, when the inspection period ended, the inspectors were continuing with their reviews after licensee final review and acceptance of test results. These reviews will be addressed in the next month's inspection report.

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. The inspectors specifically focused on several of the licensee's incident investigations during the inspection period.

a. On March 5, the inspectors met with the Sequoyah Nuclear Plant Site Quality Assurance organization in order to receive a briefing of QA activities accomplished during the past month. The resident inspectors and site QA meet monthly to discuss licensee performance and audit finding issues. The site QA monitoring group discussed several recently completed assessments in the work control, surveillance, and engineering areas. QA has used the Quality

Monitoring Group to support immediate plant management requests for evaluation of areas which appear to be experiencing problems. The inspectors have noted that the monitoring group assessments are in line with their perception of problems and provide plant management timely feedback on issues of concern.

The QA Auditing Group also was very thorough in conduct of audits and was providing the plant with findings and overall conclusions such that corrective actions could focus on programmatic issues. The inspectors noted that QA auditors also reviewed licensee corrective actions for audit findings and followed up with field reviews of corrective actions to evaluate effectiveness.

The inspectors consider that the Site QA Organization was performing a very good job in all areas including auditing activities, monitoring activities, and quality control activities. This performance was identified as a strength.

b. On March 5, the inspectors attended a licensee PERP meeting on Incident Investigation II-S-92-018. The issue involved a loss of Unit 2 level indication on no. 2 cold leg accumulator. The event occurred on February 15, 1992 and required entry into TS 3.0.3 for approximately 30 minutes. The root cause was determined to be failure to read, comprehend and follow procedures. Maintenance personnel responded to a request from shift operations personnel to perform an additional test to check out a recently replaced annunciator card. This test was not specifically called for in the work plan, although the work plan did include instructions for minor testing. The worker failed to read a caution in the work procedure which warned which kinds of cards should be tested by shorting, and which kinds of cards should be tested by lifting leads. As a result, he incorrectly shorted across leads to test the operation of an annunciator card, and caused a breaker to open which supplied power to several control room instruments. The breaker was quickly located and closed to return the instruments to operation. The licensee investigation was found to be complete and adequate in determining the root cause.

c. During this period, several LERs were reviewed for closeout. The inspectors noted that the quality of LERs which had been prepared during the November/December 1991 timeframe had improved. The inspectors specifically noted that the format had been modified to include a better description of events. The format also included a sequence of occurrences which allowed for a better understanding of the event cause(s). This improved format for LER documentation was considered to be a strength.

d. On March 10, the inspectors attended a licensee PERP meeting on Incident Investigation II-S-92-015. The issue involved the NRC identification of a failure to initiate a required 10 CFR 50.59 evaluation as required by SSP-12.53, ANNUNCIATOR DISABLEMENT, Revision 1. This event was also discussed in NRC Inspection Report 327, 328/92-03, in which, a violation was identified for a failure to follow the requirements of SSP-12.53. The root cause of the event was attributed to inadequate communications of management's expectations regarding the incorporation of changes to the annunciator disablement process as disseminated by a change to SSP-12.53. Due to the inadequate communications of the annunciator disablement process, and inadequate knowledge of the procedures and responsibilities, various licensee personnel assumed the required 50.59 evaluation was either previously completed or being initiated by other site organizations. Corrective actions for the event are in progress and will be evaluated during review of the licensee's response to the violation.

e. On March 2 and 16, the inspectors monitored licensee PERP meetings on Incident Investigation II-S-92-021. A condition was discovered, where, from December 6, 1991 to February 19, 1992, the Unit 1 upper airlock was installed with a tie wire, such that the interlock mechanism for the outer door was defeated. In this condition, the outer door was capable of being opened when the inner door was already open. Containment breach annunciation was received in the control room by operators on February 5 during a routine containment entry; however, the alarm cleared itself after four seconds. A WR was initiated to troubleshoot the airlock limit switches. The condition was eventually discovered during routine maintenance on the airlock. The licensee subsequently determined that no actual breach conditions existed, including the alarm anomaly which occurred on February 5.

The root causes of the event were determined to be inadequate usage of the configuration control log, improper inspection for the return to normal condition, and lack of performance of the PMT. The latter PMT was initially planned for the work; however, was subsequently deleted based on a system engineering review of the scope of work. With regard to the deletion of the assigned PMT, the inspectors questioned the licensee's process which provides a two party review for assignment of adequate work PMT; however, allows the capability of single party deletion for the same PMT. The inspectors noted that management expanded the scope of several corrective actions including a review of the Unit 1 and common annunciator response procedures and a review of the PMT assignment and deletion process. The investigation otherwise was well detailed and appeared to adequately address corrective actions for the event.

f. On March 18, a PERP was held to review the results of Incident Investigation II-S-92-025. This incident involved the inadvertent initiation of a containment ventilation isolation on Unit 1. The technician performing a post-maintenance test on the Unit 2 upper containment air particulate radiation monitor, 2-RE-90-112A, mistakenly performed a step on the Unit 1 monitor, 1-RE-90-112A. After performing one step on the Unit 2 monitor, the technician paused to make a report to operators, and then turned and incorrectly performed the next step on the Unit 1 monitor. Since the initiation signals from the Unit 1 monitor were not blocked, a containment ventilation isolation occurred.

Facility investigations concluded that the root cause of the inadvertent initiation was determined to be the technician's failure to perform a self-check before performing the operation. A contributing factor was determined to be the poor discrimination of Unit 1 and 2 components on the control panel. Inspectors reviewed the facility investigation report and concluded that licensee investigations were well conducted and accurate in their conclusions. It was noted that previous similar events had resulted in the identification of a human engineering deficiency in panel layout, and that action has, and will continue to be taken to improve the separation of radiation monitors into functional groups.

g. On March 22, the inspectors monitored licensee a PORC meeting which considered changes made to the Unit 1 ice condenser (paragraph 4.d). A safety assessment of changes to the insulation under the lower ice condenser doors was first considered. The change replaced fiberglass bag insulation with foam strips attached to the inner surface of the polar crane wall. Appropriate management attention was given to consideration of all aspects of the proposed change including the adhesive selected, effects of future wear slab movement, and installation plan.

A safety assessment/safety evaluation of the operability of the ice condenser following wear slab movement was also considered. The evaluation considered structural effects on the steel members affected by the wear slab movement. The facility concluded that the increased stresses induced by the slab were within the allowable stresses in structural members and fasteners. Also, the facility considered the effects of the new floor geometry on ice condenser performance under accident conditions and concluded there would be no adverse effects. The PORC imposed a condition upon acceptance of the change in that the plan for monitoring for future movement be reviewed and approved by PORC prior to Unit 1 startup. This was completed on March 26. Also, the PORC directed that the gap created between the floor drain and the wear slab should be addressed. The PORC then approved the evaluation.

Following PORC approval, inspectors pointed out to the facility that the evaluation had failed to consider one design criteria found in the FSAR. The FSAR stated that the distance between the floor and the bottom of the door is important to absorb ice accumulation during a seismic event coincident with a LOCA. The evaluation failed to discuss the effect of the reduction in the distance between the floor and the bottom of the door on this accident. The facility informed the inspectors that this condition had been evaluated and considered, but had not been included in the report. As a result of the inspector's comments, the licensee added the results of their analysis in this area to the evaluation prior to final signature by the PORC chairman.

h. On April 1, the inspectors attended a licensee PERP meeting on Incident Investigation II-S-92-027. The issue involved the occurrence of a feedwater line leak on the Unit 1, number 3 SG. The inspectors considered the facility's investigation to be thorough and well conducted. The root cause was determined to be inadequate non-destructive testing of the weld joint during regular ISI program inspections. Details of this event are contained in paragraph 4.e, and in Inspection Report 327, 328/92-09.

i. On April 1, the inspectors attended a licensee PERP meeting on Incident Investigation II-S-92-026. The issue involved the discovery of inoperable ice condenser door on Units 1 and 2. The inspectors considered the facility's investigation to be thorough and well conducted. The root cause was determined to be a combination of inadequate original installation, inadequate engineering review of a proposed construction change, and poor maintenance practices. Details of this event are contained in paragraph 4.d, and in Inspection Report 327, 328/92 10.

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.

(Closed) LER 327/91-23, Potential for Loss of Containment Sump Inventory to Outside Containment During a Small Break Loss of Coolant Accident. The event involved identification of a condition where a high suction pressure for the centrifugal charging pumps could possibly lift the seal water heat exchanger relief valve and divert containment sump inventory to the volume control tank during a small break loss of coolant accident. Immediate actions were taken to brief operations personnel of the possible event along with appropriate mitigating actions. This event was discussed in Inspection Report 327, 328/91-19. The inspectors consider that licensee corrective actions for this event were adequate.

(Closed) LER 327/91-25, Main Steam Isolation Valves Inoperable Because Jumpers Had Not Been Removed Following Maintenance. The event involved the licensee's failure to remove jumpers from safety-related components resulting in a violation of TS. This event was fully discussed in Inspection Report 327, 328/91-31. As a result of that review, a violation was issued for failure to follow procedure which caused the TS violation. The inspectors have reviewed the licensee's immediate corrective actions for the event and consider them to be adequate. Review of long term corrective actions will be accomplished during closeout of the violation.

(Closed) LER 327/91-26, Insufficient Vendor Information Results in a Lack of Selective Breaker Coordination. The event involved licensee identification of a breaker coordination problem during testing. The problem was later attributed to a lack of vendor information with regard to the type of trip circuitry provided in Westinghouse DS breakers with type LS amptectors. Immediate corrective actions included modification of the amptectors. During the modification of breakers on 480-V shutdown board 1B2-B, a short circuit condition occurred resulting in a requirement to make extensive repairs to the board. These events were fully discussed in Inspection Reports 327, 328/91-26 and 91-27. The inspectors consider that licensee corrective actions for these events were adequate.

(Closed) LER 327/91-27, Manual Closure of the Main Steam Isolation Valves as a Result of a Malfunction of a Steam Dump Valve Controller Resulting in a

Cooldown of the Reactor Coolant System. The event involved operator action to minimize a cooldown of Unit 1 when a steam dump valve controller failed and caused two steam dump valves to open. The inspectors reviewed the licensee's immediate corrective actions and the corrective action for the faulty controller. This event was discussed in inspection report 327, 328/91-31. The inspectors consider that licensee corrective actions for these events were adequate.

(Closed) LER 328/91-01, Automatic Feedwater Isolation and Subsequent Auxiliary Feedwater System Start as the Result of a High-high Steam Generator Level and LCO 3.0.3 Entry for More Than One RPI Bank Inoperable. This event involved an AFW actuation which occurred due to high SG levels resulting from a sudden load change due to a turbine EHC malfunction. Additionally, after the transient, two RPIs deviated from bank positions by greater than 12 steps due to temperature change effects on RPI calibration. The licensee has completed procedure changes to formalize turbine runback recovery procedures, and has completed additional operator training on the EHC system to enhance operator ability to respond to EHC malfunctions. Also, the licensee has completed the evaluation of actions to prevent future RPI calibration drift problems resulting in TS LCO 3.0.3 entry. These actions have been combined with several other related issues into TS change requests which are currently in development. The inspectors consider that licensee corrective actions were adequate.

(Closed) LER 328/91-05, Surveillance Requirement Time Interval Exceeded Because of Untimely Failure of P-250 Process Computer. This event involved the failure to perform a required secondary heat balance to verify neutron instrument calibration. Operators were unable to complete the required surveillance manually in the short time available after a failure of the P-250 process computer, which is the normal method of calculation. Corrective actions included improvements to the P-250 computer preventative maintenance program, changes to P-250 printouts to improve data records, and various actions to review the event with operations and instrument maintenance personnel. The inspectors consider that licensee corrective actions were adequate.

(Closed) LER 328/91-06, Reactor Trip on Low-low Steam Generator Level Resulting From an Inadvertent Main Steam Isolation Valve Closure Caused by a Limit Switch Failure. Licensee corrective action included modifications to the MSIV limit switches, and changes to maintenance procedures to improve the guidance for valve maintenance. Inspectors confirmed that corrective action to replace the limit switches with a newer model was completed on March 27. Inspectors also reviewed revisions made to 0-MI-MVV-001-004.0, MAIN STEAM ISOLATION VALVE MAINTENANCE, Revision 1, and found that changes had been accomplished to ensure proper disassembly and reassembly of the MSIV metering devices. The inspectors consider that licensee corrective actions were adequate.

Within the areas inspected, no violations were identified.

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

   a. (Closed) TI 2500/14, Inspection of the Location of the Manual Trip Circuit in Westinghouse Designed Plants with a Solid State Protection System (SSPS). The issue involved determination of the location of the connection point for the manual reactor trip switches with respect to the electronics circuitry including output transistors Q3 and Q4 in the SSPS. The inspectors reviewed the licensee drawing # 1296H46, SSPS SCHEMATIC DIAGRAM, Revision B, which was the current controlled drawing addressing the issue, and determined that the manual reactor trip switches connection points were downstream of the output transistors Q3 and Q4 which was determined to be the proper (conservative) connection point for this issue. The inspectors also reviewed the drawing control and determined that the proper control drawings were available for use by plant personnel.

   b. (Closed) TMI Item II.F.1.2.F, Containment Hydrogen Monitor. This issue was previously discussed in Inspection Report 327, 328/90-32. In that report, WP 229-02 was reviewed, which was written to implement the mechanical portions of DCN 229 and the electrical portion of WP 229-02. Step 3 of WP 229-01 installed solenoid valves to replace the inboard and outboard air operated isolation valves and test connections for these valves. The implementation of the WP was found to be acceptable in report 327, 328/90-32 with the exception of a control room (CR) valve labeling discrepancy problem and closure of the associated WPs. The inspectors determined that the CR valve labels (on the handswitches) depicted the Unit 1 containment isolation valves as air operated valves although the valve operators had been replaced with solenoids. During this inspection period, the inspectors reviewed WP 229-01 with regard to the valve labeling issue. The WP did identify appropriate valve tagging to be accomplished in the field after valve changeout; however, the workplan did not address correction of the CR valve identification tags. The inspector found that this issue, identified to the licensee in report 327, 328/90-32, currently remains uncorrected. In addition, no tagging requests were identified to address the problem. The inspectors discussed this issue with the licensee. PER SQPER920068 was initiated for the CR valve labeling condition and subsequent identification that DCN 229 and the associated workpla[illegible] were closed without the appropriate label changes being impl[illegible]nted. Tagging requests were then issued to correct the outstanding problems.

This problem is similar to a non-cited violation described in paragraph 4.a of this report, in that, necessary work associated with a modification was not accomplished. However; in this instance, the required work was not identified to be performed in the workplan. The inspector reviewed the licensee's current program for assuring that the required tagging of modified components is accomplished, and concluded that impr[illegible]vements incorporated since the valve tagging problem occurred should preclude recurrence of the problem. The inspectors considered the licensee's actions in this area to be adequate.

c. (Closed) 327, 328/P2190-07, Part 21 Report from ASEA Brown Boveri Inc. - ABB 27/59 Relay Has Deteriorated Leads Due to Thermal Stress. The issue involved vendor identification of degradation of solder connections on the subject relays. The vendor notified TVA of this condition and identified that Sequoyah had procured 12 of the subject relays. The licensee wrote a condition adverse to quality report (SQP900116) and determined that 4 of the relays were installed in compartment 17 of the 6.9 Kv shutdown boards (Alternate Power Supply to Shutdown Board). The licensee reviewed the installation of the 4 relays in the shutdown boards and determined that they had been installed as spares and not wired into circuitry. Action has been taken to replace the relays prior to use. Also, a licensee review of use of the other eight relays did not identify any location where they may have been installed; however, the licensee has not been able to locate them. The licensee concluded that the eight relays were disposed of as surplus during the last eight years and are no longer at Sequoyah. They also consider that procedures are in place to prevent inadvertent use of these components into safety-related applications based on identification of the subject problem. The inspectors reviewed the licensee's actions for this issue and consider the actions to be adequate.

d. (Closed) IFI 327, 328/90-01-04, Problems with Test Gauges. The issues involved two concerns identified in a licensee Root Cause Analysis (RCA) investigation report dated January 11, 1990. The first issue recognized concerns with obtaining accurate test results when large pressure gauge pulsations occurred during the performance Section XI pump testing. The licensee evaluated the problems which were identified initially during RHR testing. The results of the evaluation concluded that dampening devices were not normally used during testing, and that training on gauge reading techniques was not emphasized. As corrective action, the licensee instituted training for the appropriate personnel on the use of dampening devices and other techniques to enhance instrument readings. Inspectors have noted, during recent observations of various Section XI pump testing, that correct precautions are taken by test performers to facilitate proper gauge indications.

The second concern noted in the RCA investigation report was an issue where calibration test results indicated a possible adverse trend of problems with M&TE. To determine if the indicated trending problem still existed, the inspectors reviewed the licensee's current program for control of M&TE as detailed in SSP-6.7, CONTROL OF MEASURING AND TEST EQUIPMENT, Revision 0, and inspected the main control point for issuing of the equipment. Licensee activities reviewed included M&TE issue, return, post-use testing, and non-conformance report processing.

The inspectors interviewed M&TE personnel on any trend information which might indicate an abnormal increase in the number of non-conformance reports. The personnel indicated that, while no specific ongoing trending was maintained, the number of non-conformance reports has remained fairly constant on a monthly basis. The individuals did indicate that the most common gauges found out of calibration following a post use test were large pressure gauges, and that most often, this was the result of abuse in the field. The inspectors discussed the process in which repetitively out of calibration equipment is identified and corrected. The licensee indicated that the M&TE group performs a historical review for equipment which is non-conforming. Once non-conforming equipment is identified as being prone to failure (on a 2 out of 5 failure per use basis) the equipment is evaluated for further use or replacement. The inspectors noted that this 2 out of 5 criteria was not prescribed in any procedure. Upon further discussions, the licensee decided to add these parameters to existing procedures to ensure consistency. The inspectors concluded that the process for monitoring and disposing of out of calibration equipment was being adequately accomplished.

The licensee's program was also reviewed for the timely evaluation of the impact of out of calibration equipment on the operability of safety-related equipment. The inspectors examined the licensee's processing of the non-conformance evaluations for the effects of equipment found to be out-of-tolerance following use. Two months following the identification of problems in this area by a QA audit (SQFIR910123201), problems continued to exist in the processing of non-conformance reports. On the date the inspectors visited the M&TE issue point, there were approximately 68 outstanding non-conformance reports. Ten of the 68 outstanding non-conformance reports had exceeded SSP-6.7 requirements, in that the required review had not been completed within 30 days. All ten of these were in review by the Electrical Maintenance Group.

In addition, several non-conformance reports were selected at random and reviewed for proper evaluation of the impact of out-of-tolerance conditions on the maintenance for which the equipment had been used. Licensee action appeared to be adequate, although sometimes lacking detailed analysis.

As a result of the QA findings and the inspectors' concerns, the licensee took action to enter the tracking of non-conformance reports into the TROI system when they are within 7 days of their due date. The licensee is also considering increasing this time to 1[illegible] days, which they believe to be achievable based on a review of actual completion times. The licensee believes that this process will ensure items are completed in a timely manner. The licensee also informed inspectors that PERs had been, and will continue to be, initiated by M&TE personnel when non-conformance reports exceed 30 days. Inspectors considered these actions by the licensee to be adequate to prevent future problems in this area.

Failure to complete the required reviews for non-conformance reports within 30 days as required by SSP-6.7 is identified as a non-cited violation (327, 328/92-06-03). The violation is not being cited because the criteria specified in Section V.A of the Enforcement Policy were satisfied. The inspectors consider that licensee corrective actions for this follow-up item were adequate.

Within the areas inspected, one non-cited violation was identified.

9. TI 2515/113 Reliable Decay Heat Removal During Outages - Unit 2

During this period, the inspectors reviewed the licensee's activities during the Unit 2 outage which had the potential for contributing significantly to a loss of capability to remove decay heat from the reactor.

On March 20, inspectors reviewed licensee actions supporting reactor coolant operations with level just below the reactor vessel flange. The licensee had lowered level in preparation for the removal of the reactor head for refueling operations. Licensee management discussed the evolution with inspectors and informed them that to reduce shutdown risk, work would not be allowed in the switchyard while the 2A-A EDG was out of service. However, during plant tours, inspectors found that the 2A-A EDG was out of service for weekly maintenance, and, at the same time, three minor work evolutions were in progress in the switchyard. Inspectors concluded that contrary to management's expectations, the SOS had allowed limited minor work to be done in the switchyard. Licensee management reviewed the inspectors concerns, and directed that all work in the switchyard be stopped until the RCS level was returned to the pressurizer level indicating range.

On March 26, after RCS level had been restored for refueling operations, a second problem occurred with communication between management and shift supervision on protecting RHR. With Unit 2 in MODE 6 and RCS level at refueling levels, shift personnel authorized work on both the 2A RHR pump and the 2B-B EDG simultaneously. Although not exceeding any TS requirements, this evolution was contrary to management's plans. Management informed the inspectors of this evolution and immediately took actions to return the EDG to service in accordance with their expectations. Also, to ensure these expectations were being clearly communicated between management and shift supervision, the licensee issued a standing order (92-001) to clearly define requirements for electrical power during RHR operation. This standing order required maintenance of at least two barriers for protection of forced core flow by preventing work simultaneously on power supplies or pumps of opposite RHR trains.

Inspectors also reviewed licensee actions in regard to the maintenance of proper RCS level indications during periods of operation below the pressurizer indicating range. Inspectors found that the licensee was having material problems with the liquid level gage, which normally covers the range between the pressurizer and the RCS sightglass indicating ranges. This caused some minor confusion initially during level changes. However, the licensee was quick to compensate by establishing communications between the control room and personnel visually observing level at the refueling canal.

Inspectors continued to monitor licensee operations when RCS level was below the pressurizer indicating range throughout the remainder of the inspection period. The facility became consistent in the practice of not allowing work in the switchyard whenever RCS level was below the pressurizer level indicating range. The facility also adopted an operating policy of protecting both trains of RHR by not allowing any RHR-related work when RCS level was below the pressurizer indicating range and fuel was present in the reactor vessel. Inspectors considered these actions to be good practices in reducing the risk of a loss of decay heat removal capability. Management attention has been evident in this area.

Within the areas inspected, no violations were identified.

10. Exit Interview

The inspection scope and results were summarized on April 7, 1992 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. Although proprietary material was reviewed during the inspection, proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Item Number	Description and Reference
327, 328/92-06-01	Non-cited Violation - Failure to follow the requirements of AI-19 in that work activities were not properly completed.
327, 328/92-06-02	Apparent Violation - Failure to meet the requirements of TS 3.6.5.3 for ice condenser door operability.
327, 328/92-06-03	Non-cited Violation - Failure to follow the requirements of SSP-6.7 with regard to M&TE non-conformance reviews not completed within 30 days.

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.

11. List of Acronyms and Initialisms

AFW	Auxiliary Feedwater
AI	Administrative Instruction
ALARA	As Low As Reasonable Achievable
AUO	Auxiliary Unit Operator
CAL	Confirmatory Action Letter
CCP	Centifugal Charging Pump
CCS	Component Cooling System
CFR	Code of Federal Regulations
CR	Control Room
CVI	Containment Ventilation Isolation
DCN	Design Change Notice
EDG	Emergency Diesel Generator
EHC	Electro-hydraulic Control
ERCW	Essential Raw Cooling Water
ESF	Engineered Safety Feature
FSAR	Final Safety Analysis Report
GPM	Gallons per Minute
IFI	Inspection Follow-up Item
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
MI	Maintenance Instruction
MSIV	Main Steam Isolation Valve
M&TE	Measurement and Test Equipment
NRC	Nuclear Regulatory Commission
PCR	Personnel Contamination Report
PER	Problem Evaluation Report
PERP	Plant Evaluation Review Panel
PMT	Post-maintenance Test
PORC	Plant Operations Review Committee
QA	Quality Assurance
RAR	Radiological Awareness Report
RCA	Root Cause Analysis
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RPI	Rod Position Indication
RWP	Radiation Work Permit
SFP	Spent Fuel Pit
SG	Steam Generator
SI	Surveillance Instruction

SSP	Site Standard Practice
TMI	Three Mile Island
SSPS	Solid State Protection System
TROI	Tracking and Reporting of Open Items
TS	Technical Specifications
TVA	Tennessee Valley Authority
WP	Work Plan
WR	Work Request