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

Report Nos.: 50-327/94-04 and 50-328/94-04

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: January 9 through February 10, 1994

Lead Inspector: William E. Holland 2-28-94
W. E. Holland, Senior Resident Inspector Date Signed

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

Approved by: P J Kellogg 2/28/94
Paul J. Kellogg, Chief, Section 4A Date Signed
Division of Reactor 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 Operations, a violation was noted for failure to take effective actions for past configuration control problems. The actions were considered ineffective due to the recurrence of additional problems this period resulting in inadvertent opening of an accumulator isolation valve, installation of fuses such that annunciation would not be alarmed if the fuse blew, and failure to place an AFW pump control switch in the proper position for approximately six hours (paragraph 3.a).

In the area of Engineering, a weakness was noted in thoroughness and quality of the engineering evaluation documentation for backleakage through a safety-related charging pump check valve (paragraph 6.a).

During an Operational Readiness Assessment Team inspection (327, 328/93-201) for Unit 2 in August/September of 1993, the following issues were identified (paragraph 8.a).

- Several examples of a violation of 10 CFR 50, Appendix B, Criterion V for Failure to Provide and/or Follow procedures for Activities Affecting Quality.

- A violation of 10 CFR 50.59 for Failure to Perform a Safety Evaluation for a Change to the Facility as Required by Regulations.

After further review, these issues will be identified as violations in this inspection report.

In the areas of Operations and Engineering, an apparent violation was identified for inadequate monitoring/control of Unit 1 reactor vessel inventory during shutdown conditions (paragraph 8.b).

In the area of Maintenance, an example was identified in which the licensee's predictive maintenance program did not predict the failure of the 2B-B CCP shaft (paragraph 4.a).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

O. Zeringue, Senior Vice President, Nuclear Operations
*R. Fenech, Site Vice President
*K. Powers, Plant Manager
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
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. Ward, Engineering and Modifications Manager
N. Welch, Operations Superintendent

NRC Employees

R. Crlenjak, 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.

2. Plant Status

Unit 1 began the inspection period in MODE 5 (day 279 of the Cycle 6 refueling outage). During the inspection period, Unit 1 remained in MODE 5 with efforts continuing to correct restart deficiencies. At the end of the inspection period, Unit 1 remained in MODE 5 with restart corrective actions continuing.

Unit 2 began the inspection period in MODE 4 with repairs continuing on the 2B CCP. Repairs were completed on the 2B CCP, the main generator hydrogen leak, and approximately 50 other work items on the secondary plant. The unit was taken critical and connected to the grid on January 12, 1994. The unit operated at power for the remainder 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.

(1) Inadvertent Injection of Unit 2 ECCS Cold Leg Accumulator

On January 10, with Unit 2 in Mode 4 at approximately 340 °F and 528 psig RCS, the licensee was making preparations to enter Mode 3 and was working to complete the ECCS Master Checklist-B of GOI-1, UNIT HEATUP FROM COLD SHUTDOWN TO HOT STANDBY, Revision 98. The checklist requires, in step II.C.2., the verification of control power "on" and valve "closed" indication for each of the four CLA isolation valves. The ASOS, after a pre-evolution briefing with control room operators, instructed that operating power be restored to the valves so that they could be opened after reaching the required pressure in Mode 3. Operators were dispatched to release hold clearance HO 2-94-30 which would restore operating power to the valves. At 7:16 p.m. when operators closed the power supply breaker to 2-FCV-63-118 (CLA #1 isolation valve) the valve began to stoke open due to an unanticipated sealed-in valve "open" signal. Operators took immediate action to reopen the power supply breaker and reclose the MOV. However, during this brief evolution approximately 90 gallons of borated water was injected into the RCS.

The inspectors reviewed the circumstances surrounding this licensee identified event and determined that there was little safety significance from the standpoint of nuclear or personnel safety. The borated water injection added additional shutdown margin to the reactor. In addition, minimal thermal shock was experienced due to the low temperature of the RCS. However, the inspectors were concerned because the normal operator barriers which should have prevented the event had failed and resulted in the loss of configuration control of an ECCS system. Specifically, there appeared to be a lack of a questioning attitude by the control room staff as to potential consequences of restoring operating power to these valves sooner than procedurally required. GOI-1, step V.C.8, states that the CLAs are to be placed in service when RCS pressure is greater than 900 psig but less than 1000 psig. Additionally, operators are to cycle the control power supply breakers to drop out the open contactor prior to energizing the power supply to the valve. If this action had been taken, any sealed-in signal would have been cleared and the valve would have remained closed when energized.

The licensee determined during its event critique that the sealed-in "open" signal was probably caused by the performance of a periodic instruction on the 2-III 120 volt vital invertor. Failure of this invertor causes certain actuation logic to become sealed-in. During performance of the periodic instruction, the invertor lost power long enough to lock in the valve open signal.

The licensee concluded that the root cause of the event was that personnel did not fully evaluate the cause and effect of placing power on the CLA isolation valves. The personnel involved discussed lifting the clearance but failed to remember that cycling the control power breaker was required in order to drop out the open contactor for the CLA isolation valve. This resulted in the opening of the valve when power was placed on the breaker.

The licensee plans to remove section II.C.2, related to ECCS CLA verification, from the ECCS Master Checklist-B. Also under review is a design change (and TS change) to remove the isolation valve "open" logic. An Operator Aid has been installed at each CLA isolation valve power supply breaker cautioning that the control power must be cycled prior to closing the power supply breaker.

(2) During a MRC meeting on January 25, 1994, the inspectors became aware of a licensee identified problem associated with installation of FLAS 5 fuses in the plant. The problem, addressed in PER SQ940043 involved discovery of several FLAS 5 fuses installed such that a fuse failure would not have annunciated an alarm to the operators. The same problem had been identified by the licensee in August of 1993. Corrective actions for the problem at that time included training of operators on proper installation of the fuses. In addition, the plant was walked down to correct any improper installations and ensure configuration. latest

problem appears to have occurred after the training and configuration corrective actions had been completed for the August problem. Initial reviews by the licensee have determined that the latest cause appears to be a lack of attention to detail in assuring that FLAS fuses are installed correctly. At the end of the inspection period, the licensee was continuing with corrective actions for the latest problem.

(3) On January 31, 1994, the inspectors reviewed a licensee identified event where on January 29, 1994, a Unit 2 operator left the hand switch for the turbine driven auxiliary feedwater pump in the manual position after completion of activities requiring the handswitch to be in manual. The normal position for the switch with the unit at power is automatic. The licensee's review of this event concluded that the safety significance of the switch position was minimal, in that the automatic safety function would have occurred. However, the licensee also recognized this problem to be another example of poor operator attention to detail in maintaining proper configuration control of the plant.

The inspectors reviewed the regulatory significance of these events. They concluded that although plant nuclear safety significance was minimal, these events exhibited additional examples of operator inattention to detail and lack of full understanding of all aspects in assuring configuration control of plant components. In addition, the events were also indicative of ineffective management communication of expectations to licensee personnel. The inspectors reviewed several recent past events involving configuration control problems. Some of these events were:

- Two motor driven auxiliary feedwater pumps handswitches were found in an incorrect position in October of 1993. (Report 327, 328/93-50)

- Improper configuration control of reactor coolant drain tank valves in August of 1993. (Report 327, 328/93-39)

- Weaknesses associated with operation's procedures and inadequate configuration controls on a temporary system important to safety in July of 1993. (Report 327, 328/93-33)

The inspectors concluded that corrective actions for past events have been ineffective in preventing repetition of configuration control events discussed above. 10 CFR 50, Appendix B, Criterion XVI requires, in part, measures shall be established to assure conditions adverse to quality are promptly identified and corrected. In addition, for significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. Failure to take corrective actions to preclude repetition of configuration control problems is identified as a violation of 10 CFR 50, Appendix B, Criterion XVI (327, 328/94-04-01).

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, 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. 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.

f. Licensee NRC Notifications

(1) On January 10, 1994, the licensee made a one hour notification to the NRC as required by 10 CFR 50.72 regarding a declaration of a Notification of Unusual Event (NOUE). At 7:36 p.m., on January 10, while Unit 2 was in Mode 4 at 580 psig RCS pressure, a NOUE was entered and exited due to approximately 90 gallons of borated water being injected into the RCS from ECCS Cold Leg Accumulator #1. Operators were attempting to restore operating power to the accumulator isolation valves in preparation for Mode 3 entry when the event occurred. Operators took immediate action to close the accumulator isolation valve. This event is further discussed in paragraph 3.a.(1).

Within the areas inspected, one violation 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. 2B-B CCP Shaft Failure

During the previous inspection period (report 327, 328/93-55), the inspectors reviewed events regarding a shaft failure on the 2B-B CCP while the pump was in service. The 2B-B shaft was heat treated, Martensitic Stainless Steel type 414. The shaft was manufactured with machined threads and was oil quenched and tempered. Subsequent licensee investigation identified that the shaft failure occurred under the balance drum locknut (located near the outboard bearing on the shaft). Preliminary metallurgical data indicated that the failure was fatigue induced cracking at the locknut threads. Other industry shaft failures have also occurred in this region. To date, no failure initiating metallurgical or manufacturing flaws have been identified. However, by the end of the inspection period, the licensee had concluded that the root cause of the fatigue failure was indeterminate.

A number of potential contributors were identified and continue to be investigated by the licensee for the development of preventative measures to preclude future failures. The potential contributors included the effects of low flow operation, material/manufacturing problems, number of pump starts and stops, VCT temperature effects, and external loadings. The latter included the possibility that a microscopic fracture, induced by an initiating event in August of 1990 (gas binding), had propagated through low stress, high cycle fatigue. The 2B-B shaft failed after approximately 45,136 hours of operation and approximately 134 pump starts, both of which were not abnormally high, according to the pump vendor.

The inspectors reviewed historical information relative to key operational indicators on the 2B-B CCP and other CCPs, which had been available for trending prior to the current shaft failure. Two notable events were identified. In August 1990, the 2B-B CCP experienced a gas binding event due to hydrogen collecting in its suction header. In February of 1991, a failure of the 1B-B CCP occurred due to the ingestion of boric acid crystals and/or gas into the pump's suction. Due to the failure of the 1B-B CCP, the licensee added balance drum flow and outboard bearing vibrations to other key parameters already being taken in order to better predict future failures. The inspectors noted that shortly after the 2B-B gas binding event, balancing drum flow and bearing vibrations for the 2B-B were higher than the similar parameters on the other three CCP's. Although not exceeding vendor operating limits, the balancing drum flow and outboard bearing vibrations for the 2B-B CCP were 10 to 15 gpm and 0.5 to 0.7 mils higher than the other CCPs parameters. These indications, however, remained stable from approximately mid 1991 to the time of the 2B-B shaft failure. Due to the lack of available data prior to the gas binding event for balance drum flow and outboard bearing vibrations, the inspectors could not definitively conclude that the gas binding event induced a flaw which resulted in the recent failure of the 2B-B CCP.

By the end of the inspection period, the licensee's metallurgical analysis of the failure mechanism was inconclusive. This was partially attributed to the decontamination process inadvertently involving wire brushing the failed shaft prior to the final metallurgical examination. With exception to the above, the inspectors considered the licensee's initial investigation of the shaft failure event thorough. The inspectors will review the final Incident Investigation (II SQ940012) and metallurgical reports regarding the 2B-B shaft failure once completed.

The inspectors also reviewed the relevant 2B-B replacement pump operating parameter characteristics to ascertain the compatibility with the existing system. The vendor supplied pump operational curves provided a close match to the parameters of the failed CCP. Based on the suitability of the new pump curves, the licensee determined that the post maintenance testing for the pump replacement would be the performance of the routine Section XI testing, which is performed on a quarterly basis. Based on reviews of the above and the performed PMT, the inspectors concluded that the repair and testing activities were completed in an adequate manner. However, this example indicated that the licensee's predictive maintenance program did not predict the failure of the 2B-B CCP shaft, which warrants additional licensee attention.

b. 1B-B CCP Bearing Failures Due To Reverse Pump Rotation and CCP Discharge Check Valve Leakage.

During the inspection period, the inspectors reviewed repairs being made to the Unit 1 1B-B CCP. In November 1993, operators identified that the pump was rotating backwards. It was postulated that the pump's discharge check valve was leaking, resulting in backwards rotation. The licensee inspected the 1B-B pump and identified damage to both the inboard and the outboard bearings for the pump. In addition, the bearings had scored the pump shaft which required its replacement. The licensee determined that the root cause of the bearing failure was the reverse rotation of the pump, which in turn was caused by the leaking through of the 1B discharge check valve. During the period of reverse rotation, no oil was being supplied to the bearings (babbitt type), due to the shaft driven pump only operating in the forward direction of rotation. Historical vibrational data was reviewed and indicated that no previous problems were apparent, which supported the theory of bearing failure due to the reverse rotation. The repair activities included shaft, bearings, and pump casing replacement, the later being a vendor recommended upgrade to a SS material. All of the CCPs now have the SS pump casing upgrade. PMT for the activity included Section XI testing and future system flow balancing to be performed in MODE 4. The inspectors will monitor the final PMT for the 1B-B CCP during future inspections.

The leaking 1B-B discharge check valve was inspected for damage. Severe damage (erosion) was apparent on both the seat and disc; however, structural integrity of the valve still appeared to be intact. The valve was removed, refurbished, and reinstalled. Coincident with the 1B-B repair activities, in December 1993, during ASME Section XI pump testing, the licensee identified that the 2B-B CCP discharge check valve was also leaking through; however, no reverse rotation of the 2B-B CCP was identified. Due to this condition, operators were informed to closely monitor the pump for reverse rotation and to operate the 2B-B as the preferred pump to eliminate the concern. The inspectors noted that PER SQ930832 was initiated for the leakage through the 2B-B discharge check; however, no PER was initiated for the degradation found on the 1B-B discharge check valve. The inspectors questioned what corrective action process would review other CCP and other safety-related pump discharge check valves for similar degradation. The licensee indicated that personnel in the Section XI testing program had been furnished the 1B-B failure information and were developing testing to identify other safety-related check valve problems. Future corrective actions include testing of the 1B-B and 1A-A CCP discharge check valve prior to the unit restart from the refueling outage. The inspectors will monitor these activities during future inspections.

c. During the last inspection period, the inspectors reviewed licensee actions associated with a potential problem that had been identified for Atwood & Morrill MSIVs at another nuclear plant. The potential problem involved failure of one or more MSIVs to close during a plant transient. The licensee tested the MSIVs and determined that 2 of the 4 MSIVs failed the test criteria. One of the valves stroked slower than the required time (5.2 verses 5.0 sec. max). The other valve did not give full closed indication after stroking. The licensee immediately took corrective actions on all four of the Unit 2 MSIVs. Adjustments were made to guide bolts on the bottom spring plate to allow for thermal expansion of the valve body at NOT. The adjustment information was verbally provided by the vendor to the licensee.

On January 11, 1994, the licensee conducted additional full stroke testing of the Unit 2 MSIVs at NOT. The test results indicated that all four of the MSIVs shut between 4.0 and 4.7 seconds. The testing is also discussed in paragraph 5.a. After testing was accomplished, Unit 2 returned to power operation.

The inspectors then focused on vendor manual information or requirements for conducting maintenance on the MSIVs. The inspectors obtained a copy of the licensee's manual, SQN-VTM-A585-0010, VENDOR TECHNICAL MANUAL FOR 32" MAIN STEAM ISOLATION VALVES MANUFACTURED BY ATWOOD & MORRILL CO., INC. The inspectors reviewed the manual requirements and noted that no requirements were specified for making adjustments which would address thermal expansion considerations. The inspectors then discussed the same process with inspectors involved in review of an event at another nuclear plant. They provided the Sequoyah resident inspectors with information from that licensee. The information included a page taken from a vendor manual which provided guidance for adjustment of the yoke rod guides with the valves heated to operating temperature. The information specified a clearance to be set between the yoke rod and the end of the yoke rod guides.

On February 1, 1994, the inspectors attended a plant event review panel meeting which addressed MSIV yoke rod guide adjustment. The licensee's evaluation concluded that no information had been provided by the vendor prior to receiving verbal guidance in January of 1994. The inspectors informed the licensee that they believed that vendor information had been provided in written form to other licensee's prior to the event. They requested the licensee to review their vendor information process to determine if they had received such information. At the end of the inspection period, the licensee had informed the inspectors that their reviews concluded that vendor information had not been provided for hot adjustments to the MSIV yoke rod guides. The licensee also stated that the vendor was requested to provide information to update the manual. The inspectors will review this area as part of routine vendor manual reviews in the future.

The inspectors concluded that the licensee's initial response to the event for their operating unit was good and provided appropriate corrective maintenance to set proper clearances on the MSIV yoke rod guides.

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 January 14, 1994, the inspectors reviewed 2-SI-SXV-000-003.0, FULL STROKING OF CATEGORY "A" AND "B" VALVES DURING COLD SHUTDOWN, Revision 0. A special performance of the procedure was used to conduct full stroke testing of the Unit 2 MSIVs in MODE 3 on January 11, 1994. The inspectors noted that this test was being conducted to resolve deficiencies discussed in paragraph 4.b. The inspectors reviewed the completed data sheets for the test and noted that stroke times for the MSIVs were as follows:

- 2-FCV-1-4 Time - 4.6 seconds
- 2-FCV-1-11 Time - 4.0 seconds
- 2-FCV-1-22 Time - 4.3 seconds
- 2-FCV-1-29 Time - 4.7 seconds

The inspectors review concluded that the MSIV stroke times were less than the maximum allowable stroke time of 5.0 seconds. In addition, the times of each valve improved over the hot stroke times recorded prior to adjustments discussed in paragraph 4.a.

b. On January 22 and 24, the inspectors reviewed portions of 0-SO-68-1, REACTOR COOLANT SYSTEM FILLING AND VENTING, Revision 11. This procedure was being performed as part of the recovery for the Unit 1 gas accumulation event as discussed in paragraph 8. The venting and filling process involved ensuring proper system alignments to support the running of all RCPs to adequately sweep gas voids in the RCS to the reactor vessel for venting. The inspectors verified the prerequisites specified in the procedure had been met and reviewed the total amounts vented from the RCS throughout the process. The inspectors concluded that operators performed the procedure in an adequate manner and that sufficient data was taken by Technical Support personnel to estimate the gas volume in the SG tubes. No discrepancies were identified.

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.

a. On December 21, 1993, during performance of 2-SI-SXP-062-001.B, Cer' 'fugal Charging Pump 2B-B Operability Test, Revision 0, the \ ) identified a back-leakage of approximately 3.5 gpm th. the CCP 2B-B discharge check valve, 2-62-532. Subsequently, a PER, SQ930832, was initiated and an engineering evaluation was written which determined that a small amount of leakage does not affect the continued operability of the pump.

   The licensee w: concerned about possible reverse rotation of the pump caused b' back-leakage and what affect the leakage would have on the E ow margin of CCP 2A-A. These subjects were addressed in an engineering evaluation. As a compensatory measure, operators have been monitoring the 2B-B pump for reverse rotation during those times when it is shutdown.

   During this period, the inspectors reviewed the engineering evaluation written in response to the check valve leakage problem and discussed its content with members of the technical support engineering ff. The inspectors informed licensee technical support pers l and management that the written evaluation lacked specif.c data, such as acceptable leak rates and flow margins, to support the conclusion that pump operability was not affected. The inspectors concluded that, although an adequate evaluation had actually been performed by the engineering staff, the thoroughness and quality of the evaluation was not reflected in the written engineering evaluation document. The inspectors considered the documentation of this engineering evaluation to be a weakness.

b. On January 20, 1994, the inspectors reviewed activities associated with a MRRC meeting. The meeting was held to review a listing of work requests that had been proposed for deferral from the Unit 1 Cycle 6 outage. The listing included approximately 50 work requests that had been deferred since December 1, 1993.

   The MRRC generally agreed with most of the deferrals. The inspectors noted that the MRRC questioned several items and additional information was provided before deferral. However, the inspectors also noted that several items were being deferred because they were not outage dependent (i.e. could be worked at power). The MRRC agreed that these items should be assigned a priority 3 in the work control/planning process. The inspectors noted that priority 3 items were normally scheduled for work within 7 days. Since the Unit 1 Cycle 6 outage was projected to last more than 7 additional days, the inspectors questioned the licensee on whether the deferred priority 3 items would be worked ahead of Unit 1 items.

On January 27, 1994, licensee management addressed the inspectors question. Plant management stated that a new work prioritization process was being reviewed for implementation to assure that work is conducted in the proper priorities. This new process would establish two priorities which would result in immediate attention. They were priority 1 and priority 2. All other work would be rolled into a 12 week rolling schedule. The inspectors determined that the licensee was using a 12 week rolling schedule during this period in concert with the current work prioritization process required by administrative procedures. The inspectors concluded that the two processes were adequate; however, priority 3 items were difficult to address in the 12 week rolling schedules. The licensee was reviewing this area and would be making changes as necessary after additional grooming.

c. On January 31, 1994, the inspectors observed a MRRC meeting where a discussion was held relating to cable degradation on cables located in the steam generator vaults. The inspectors noted that the MRRC was reviewing corrective actions for Unit 1 restart. The licensee had approved a JCO for continued operation of Unit 2 relating to the same issue on January 29, 1994. The inspectors requested that the licensee provide additional information relating to the issue at the end of the meeting.

Over the next few days, the licensee conducted additional reviews and provided additional information to the inspectors. The original issue had been identified in PER SQ94-0040. The inspectors monitored the licensee's continuing reviews and requested additional help from Region II to continue with the reviews. On February 4, 1994, the licensee provided a draft copy of a revised JCO for continued operation of Unit 2. The inspectors provided copies of this JCO to NRC Region and Headquarters personnel and management for discussion of the issue on a telephone conference call on February 4. After the call, the NRC staff concluded that Sequoyah Unit 2 could operate safely until the next appropriate outage based on the JCO. However, the licensee agreed (1) to conduct inspections of the Unit 2 SG vault areas during the next appropriate Unit 2 outage and (2) to monitor the Unit 2 SG vault temperatures for any adverse trend that would indicate higher than normal expected conditions until the condition adverse to quality has been resolved. This issue was further reviewed by a region based inspector and was discussed in inspection report 327, 328/94-06.

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 328/93-06, Reactor Trip as a Result of Generator Exciter Problems. The issue involved a Unit 2 reactor trip from approximately 100 percent power. The licensee identified the root cause of the event to be overexcitation of the generator caused by multiple grounds in the generator exciter. Corrective action included replacement of the exciter. This event was discussed in two different inspection reports, 327,328/93-52 and 327, 328/94-02. Those reports addressed licensee corrective actions for this event.

Within the areas inspected, no violations were identified.

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

a. Items discussed in NRC Inspection Report 327, 328/93-201, OPERATIONAL READINESS ASSESSMENT TEAM INSPECTION.

The subject ORAT inspection was accomplished prior to Unit 2 restart in late August/early September of 1993. During that inspection, several issues were identified which were referred to the NRC Region II office for enforcement and followup actions. The following actions from that report are addressed in this report.

Several of the issues discussed in inspection report 327, 328/93-201 have been determined to violate NRC requirements.

10 CFR 50, Appendix B, Criterion V requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. The following issues are identified as examples of violations of 10 CFR 50, Appendix B, Criterion V. Information in parentheses identifies the paragraphs in inspection report 327, 328/93-201 that discuss each issue.

- SSP 12.3 was not followed during valve operations. (paragraph 4.5.1)

- Functional Recovery Procedure F-0.4 was determined to be inadequate. (paragraph 4.7.1)

- Test Procedure 2-SI-OPS-082-026.A was determined to be inadequate. (paragraph 5.3.1) This item was reviewed in inspection report 93-42 for corrective actions for restart of Unit 2. Additional reviews will be accomplished after the licensee formally responds to the violation.

- SSP-6.22 was determined to be inadequate. (paragraph 6.6)

- A superseded procedure (TI-104) had been used in lieu of its replacement procedure (SSP-10.5). (paragraph 6.6)

- SI 685.2 was not followed for calibration of an RHR pump room radiation monitor (paragraph 6.9)

- SSP-12.7 was not followed regarding proper securing of compressed gas cylinders in the plant (paragraph 9.2)

The above items are identified as a violation of 10 CFR 50, Appendix B, Criterion V (328/94-04-02), failure to provide and/or follow procedures for activities affecting quality.

10 CFR 50.59 (b) (1) states, in part, that the licensee shall maintain records of changes in the facility and changes in procedures made pursuant to this section, to the extent that these changes constitute changes in the facility as described in the safety analysis report or to the extent that they constitute changes in procedures as described in the safety analysis report. These records must include a written safety evaluation which provides the bases for the determination that the change, test, or experiment does not involve an unreviewed safety question.

During the ORAT inspection, it was determined that a safety evaluation was not performed after discovery of smoke detectors installed in the main control room which were not suitable for the duct-type application in which they were installed. The FSAR states that these detectors are designed to provide automatic isolation of the main control room HVAC system and initiation of the main control room emergency ventilation system upon detection of smoke. The licensee's evaluation for this detector installation did not address the FSAR design discussion. In addition, a contingency measure put in place by the licensee for operators to manually initiate the design function was removed before the issue was resolved. This is identified as a violation of 10 CFR 50.59 (b) (1), (327, 328/94-04-03), failure to perform a safety evaluation for a change to the facility as required by regulations (paragraph 4.7.3).

In addition, the following items were identified for followup during other NRC inspections. Information in parentheses identifies the paragraphs in inspection report 327, 328/93-201 that discuss each issue.

- Excessive Operations Department Overtime (paragraph 4.4)

- Weaknesses in Control Room Abandonment Drill (paragraph 4.5.2)

- Lack of Guidance for Abnormal Operating Procedures (paragraph 4.7.2)

- Backlog of Safety Related Vendor Manual Updates (paragraph 6.11)

- Emergency Lighting Deficiencies (paragraph 6.7) This item was reviewed for restart of Unit 2 in inspection report 327, 328/93-42. However, additional reviews will be conducted of the licensee's longer term corrective actions to close out this issue.

The preceding issues will be identified as an inspector followup item, (IFI 327, 328/94-04-04), followup on ORAT identified observations.

b. (Closed) URI 327/93-55-01, Unknown Accumulation of Gas in the Unit 1 Reactor Coolant System. The issue involved a significant RCS inventory level problem where nitrogen gas was unknowingly accumulated in the reactor vessel and the SG U-tubes during MODE 5 shutdown conditions. Some conditions of the event were previously described in inspection report 327, 328/93-55, which identified this URI to followup on inspector concerns regarding the event.

During the current inspection period, the licensee completed their incident investigation (II-930833). They also presented findings relative to the root causes, contributing factors, and event safety significance to the NRC in a meeting in the NRC Region II office on January 28, 1994. The following summarizes the inspectors review of the event during the current inspection period.

Event Summary

Initial conditions prior to the event were as follows. The unit had been shutdown in March 1993. After the unit was refueled, the reactor vessel reassembled, and sweeps and vents completed in early September of 1993, the RCS was depressurized and placed on a pressurizer float (approximately 50 percent cold calibration level) with an open pressurizer PORV and Tave being maintained at approximately 120 degrees F. RVLIS became available on November 29, 1993; however, RVLIS was not required to be monitored by the operators. A nitrogen cover gas was being supplied to the VCT at approximately 20 psig. The event involved nitrogen going into solution within the VCT and then transported and circulated via the charging system and RHR throughout the RCS (vessel and loop piping). Once the nitrogen solution reached areas of lower pressure and/or higher temperature, the nitrogen came out of solution and collected in the reactor head and in the SG U-tubes.

The gas accumulation event under review began after sweeps and venting of the RCS loop piping was last performed on September 6, 1993. RCS sweeps and venting were required as part of prerequisites for the CILRT pressurization. The CILRT performed on December 17, 1993 took credit for the September 6, 1993, sweep and vent evolution.

Licensee identification of gas in the RCS was first noted on December 17, 1993, during the containment pressurization for the CILRT. Operators noted a decrease in pressurizer level and the need for a significant amount of water addition was necessary to maintain pressurizer level. Undocumented evaluations were performed at this time. The licensee concluded that the inventory problem would not affect the results of the CILRT. However, as discussed later in the report, proper evaluations were not performed regarding the effect of the problem on RCS level. After the CILRT was completed, the inventory problem was documented in a PER, and subsequent actions were taken for the gas accumulation including the venting of the reactor head on December 21. Within several days, initial licensee reviews indicated that the lowest level the inventory in the reactor vessel reached was one foot below flange or elevation 701. Reduced inventory conditions begin at three feet below the flange.

However, by January 13, 1994, subsequent reviews of relevant data indicated that the level in the vessel had decreased to the top of the hot leg (approximate elevation 696). This difference resulted from a failure to accurately account for gas accumulated in the SG U-tubes during initial reviews and a lack of knowledge of the RVLIS. The low vessel and SG levels existed coincident with a pressurizer level indication of approximately 60 percent (approximately elevation 735). The water level in the primary side of the steam generators was estimated to be around the level of the SG tubesheets. The inspectors concluded that, due to the gradual accumulation of the gas starting on September 6, 1993, operators unknowingly compensated for the gas accumulation in the RCS via adjustments to the charging/letdown systems, until the event was discovered on December 17, 1993.

Summary of Initial Licensee Actions Taken for Event

Although the gas accumulation was first noted on December 17, 1993, the licensee did not fully realize the scope of the problem until after the CILRT was completed. Once the initial understanding of the phenomenon was established on December 21, a reactor head vent was performed. Subsequent compensatory actions established on December 28, included the monitoring of RVLIS for trending of the level and weekly venting of the reactor head. At this time, a decision was also made not to take credit for filled SG U-tubes in lieu of an RHR subsystem train as allowed by TS 3.4.1.4, while in MODE 5 operation. On January 13, the licensee determined that the actual level in the vessel had dropped to the top of the hot leg. On January 23, final RCS sweeps and vents were completed and an RCS pressure of approximately 200 psig was established on January 25 to maintain the nitrogen in solution in the RCS. Other details of the initial actions taken for the event are discussed below.

Operator Actions Upon Event Identification

The accumulation of gas in the RCS was first identified via the need for inventory additions on December 17, during containment pressurization for the CILRT. This indicated to operators that the RCS was not a solid system, which was assumed established prior to the CILRT. During the CILRT, the containment is pressurized to approximately 13 psig and this affected the RCS inventory through an open pressurizer PORV. Although the pressurizer inventories were noted to have decreased, operators did not recognize the full potential of the problem. Operators did request that the CILRT procedure (1-SI-SLT-088-156.0) be revised to address the potential increase in pressurizer level during depressurization of the containment following the CILRT. The procedure change instructed the operators to closely monitor pressurizer level during depressurization and anticipate the inventory change. An evaluation was also conducted that determined the changes in pressurizer level would not affect the results of the CILRT if steady state conditions could be maintained during the data collection periods. The CILRT pressurization was then completed. Operators estimated that an amount greater than 5,000 gallons was added to the RCS during CILRT pressurization. The inspectors noted that the RVLIS indicators in the CR were not reviewed because operators did not consider that the system was available (RVLIS availability is discussed later in the report).

On December 20, with the CILRT data collection complete, the containment was depressurized, and approximately the same amount of inventory added to the RCS during the CILRT pressurization, was removed. On December 21, a PER was initiated for the gas problem, a vessel head vent was performed and operations requested that Technical Support review the issue. Technical Support personnel reviewed pressurizer level data and calculated a total of 6,600 gallons of gas had been in the upper plenum region of the reactor vessel. This data indicated that the lowest level in the vessel was approximately elevation 701, which is one foot below the vessel flange. This calculation later was shown to be in error due to it failing to account for the effect of gas in the SG tubes and other factors. RVLIS data was reviewed and reflected the actual lowest level at the top of the RCS hot legs; however, involved Technical Support personnel did not correctly recognize the true level due to a lack of knowledge of the RVLIS system. Subsequent review of RVLIS data and recalculation of the pressurizer level changes made during head venting identified that the actual vessel level had been near the top of the RCS hot legs.

Based on the above, the inspectors concluded that upon initial identification of gas in the RCS during the performance of the CILRT, operators and CILRT test personnel inappropriately continued with the performance of the CILRT. The inspectors concluded that, at that point, the test should have been secured and in-depth reviews were necessary to determine actual RCS levels and component inventories. A need for venting of the reactor head likely would have been determined.

Other conclusions made by the inspectors included poor initial support from the Technical Support organization. Specifically, a lack of system engineer knowledge of the RVLIS delayed the identification that the vessel level had actually fallen to the top of the RCS hot leg. This was identified as a weakness.

Previous RCS Level Deviation Events While Shutdown and RVLIS Availability

The inspectors compared the current RCS level event to a previous unknown level perturbation which occurred in April of 1993 on Unit 1. This event was described in detail in inspection report 327, 328/93-13. During the previous event, an unknown loss of RCS level occurred due to operators failure to recognize that the cold calibration channel of the pressurizer level being used for monitoring of RCS level had drifted out of calibration and/or had not been calibrated prior to a reactor draindown commencing. The event was discovered when operators noted that the liquid level gage was placed in service, it indicated that the RCS level was approximately elevation 701 (approximately 1 foot below the vessel flange) while the pressurizer cold calibration level channel (LI-68-321) indicated a level corresponding to elevation 716. Subsequent investigation into LI-68-321 indicated that the reference leg had become partially drained resulting in the incorrect instrument indication. RVLIS was not available during the draindown due to a calibration being in progress. However, the inspectors concluded that the decision not to have RVLIS available during the draindown demonstrated a low sensitivity to an important operational evolution.

During the current event, RVLIS became available for use on November 29, after a calibration was completed. However, operators were not aware of the availability due to outstanding Instrument Maintenance orange stickers on the RVLIS indicators for outstanding work being performed on the exosensor indication system. The exosensor is a digital RCS parameter display system. The RVLIS inputs to the exosensor display; however, RVLIS information was available. This event, as in the previous event discussed above, indicated to the inspectors that the licensee does not attempt to maintain the RVLIS in an available or operable condition unless it is required to be operable. The inspectors concluded that had RVLIS been available and monitored, the above degraded conditions would had been discovered and corrected much sooner.

In addition, the inspectors also concluded that the information available to operators regarding the RVLIS system was limited under some conditions. As an example, 0-GO-4.0, RCS DRAIN AND FILL OPERATIONS, Revision 7, contains information in graph form of RVLIS upper range indication versus actual RCS elevation. However, the information is only valid when the RVLIS head sensor bellows are drained. No information or correction factors are available to operators if RVLIS is operating with the sensor bellows filled, which was the condition when RVLIS became available on November 29, 1993. Of several operators surveyed, none could easily correlate RVLIS to RCS elevation. The inspectors did review selected Emergency Operating Instructions and concluded that adequate information was available for the operators to adequately utilize the RVLIS lower plenum and dynamic ranges to complete the necessary operator actions during loss of core cooling conditions. However, the inspectors also concluded that in addition to increased sensitivity in maintaining RVLIS available to operators, some procedure enhancement were warranted to fully acclimate operators with the benefits of RVLIS as an operating tool.

In addition to the above, the inspectors requested that the licensee furnish design documentation describing the basis for the RVLIS graph information contained in 0-GO-4.0, RCS DRAIN AND FILL OPERATIONS, Revision 7. Although the graph information appeared to be relatively accurate, the inspectors were concerned that the graph information available for operators reference may not have been developed with adequate technical basis or engineering reviews. At the end of the inspection period, the inspectors were informed that no detailed calculation or test data could be identified regarding the source of information used for development of the subject graph. The inspectors concluded that the licensee did not establish design control measures for the graph information data regarding the RVLIS contained in 0-GO-4.0, RCS DRAIN AND FILL OPERATIONS, Revision 7. This resulted in unsubstantiated information being available to operators for use during evolutions which could affect safety-related parameters. This issue is identified as a potential regulatory issue later in the report.

Previous Industry Events and Information

The inspectors reviewed previous industry information which was available to the licensee and could have precluded the event. Several similar events were identified and are discussed below.

NRC Information Notice 87-46, UNDETECTED LOSS OF REACTOR COOLANT, identified an industry event involving a loss of reactor coolant during shutdown conditions without the operators being aware of the problem. Delays in discovering the loss of inventory resulted, in part, from the sole use of pressurizer level as an indication of RCS inventory and a failure to use all available indications to confirm reactor inventory. Specifically, RVLIS information was available, such that a gradual decreasing trend in RCS level could have been identified. Similarly, during the Sequoyah event, the RVLIS system was available; however, RVLIS was not utilized as an operational tool to independently verify any adverse trends of the RCS inventory.

The licensee also had received an industry event notification which occurred in October 1987 at a Westinghouse facility. This event involved the appearance of gas voids in the RCS due to hydrogen and nitrogen being released out of solution as RCS pressure was decreased. The report indicated that nitrogen from the VCT lead to the formation of RCS void formations on two separate occasions. The report further indicated that a lower nitrogen cover pressure in the VCT could prevent future void formations.

The inspectors concluded that the licensee had received previous industry information relative to the current event at Sequoyah. The licensee's use of this industry information in precluding the current event was ineffective.

Inadvertent VCT Temperature Decrease/Affect on N_2 Gas

The following paragraph describes a situation which resulted in the inadvertent cooldown of the Unit 1 VCT during portions of the gas accumulation event. The affect of the VCT temperature cooldown on the nitrogen formation is also discussed.

Prior to the gas accumulation event, PER SQ 920028 was initiated due to the identification that the CVCS piping downstream of the LDHX was not analyzed for the temperature possible if the heat exchanger had a loss of CCS cooling supply. To address the concern, the PER reviewed possible failure scenarios which would result in the loss of CCS cooling. This review identified that the CCS supply control valve to the LDHX, TCV-70-192, fails open on loss of air; however, a failure of the control circuit, TS-62-78, would result in the closing of the TCV. The licensee issued DCN M09505A to correct the problem. The modification utilized a contact from an existing circuit, TIS-62-79, to detect failure of the TS-62-78 circuit, and actuate a new solenoid to cause TCV-70-192 to go full open, if the letdown temperature exceeded 145 degree F. Prior to the attempted implementation on Unit 1 in November of 1993, the modification was successfully completed on Unit 2.

WO 93-09179-00 performed the modification on Unit 1 and by November 12, 1993, all physical modification work was signed as complete following a leak inspection. The WO was then transferred to IM for calibration of loops TIS-62-79 and TCV-70-192. However, the calibration of the loops was not immediately performed. After the transfer of the WO to the IM group, the hold order for the solenoid valve was lifted and the solenoid was later reenergized around December 1, 1993, during the completion a 0-SO-62-1 CVCS power checklist 1-62-1.01. It should be noted that the SO checklist had been revised based on the modification. The returning of power to the uncalibrated loop caused the solenoid to energize and the valve to go full open. This supplied CCS to the LDHX and subsequently caused an inadvertent cooldown of the VCT. The problem went undiscovered until early January 1994, when engineering personnel researching an unrelated concern regarding low temperature effects on CCP shafts discovered the low VCT temperature.

Data indicated that the VCT temperature gradually decreased from 80 degrees in September 1993, at the rate of approximately 10 degrees per month and finally to the upper 50 degree range by the beginning of December. This gradual decrease corresponded to the lowering of river temperature due to seasonal temperature changes. When the TSV-70-192 solenoid was energized on December 1, 1993, a step change of approximately 8 degrees F occurred. This change was not observed by operators. Once the problem was identified, the licensee took actions to deenergize the TSV-70-192 solenoid and returned VCT temperature to greater than 100 degrees F.

The inspectors reviewed the low VCT temperature and its affects on the ability of the nitrogen cover pressure to go into solution and its effect of the gas accumulation event. Based on available plant data and gas solubility properties, it appeared that the low VCT temperature allowed the amount of gas introduced into the RCS to increase (higher rate at lower VCT temperatures). The inspectors concluded that although the VCT low temperature increased the rate of nitrogen accumulation in the RCS, they also concluded that the gas accumulation problem still would have occurred regardless of the VCT low temperature problem, only at a slower rate. Additionally, no requirements in the TS, FSAR, or other licensee procedures could be identified related to a minimum temperature for the VCT. However, the inspectors concluded operators exhibited a lack of sensitivity in that a step change decrease in VCT temperature was not identified.

<u>Conclusions</u>

At the end of the inspection period, the NRC was continuing to assess the overall safety significance of the event regarding loss of shutdown cooling or the ability to maintain the core in a safe condition. The inspectors concluded that this event was the second major event during the Unit 1 extended outage involving an undetected change in RCS level. The inspectors considered that the event was indicative of a lack of adequate barriers regarding the monitoring and maintaining of RCS inventory levels. In addition, this event further demonstrated that the licensee's knowledge, maintenance, and use of the RVLIS has been less than effective. Additional management's attention to this critical area is warranted based on the repetitiveness of these types of problems.

The inspectors also concluded that upon initial identification of the existence of gas in the RCS during the performance of the CILRT, operators and CILRT test personnel inappropriately continued with the performance of the CILRT. The inspectors concluded that at the time gas was discovered in the RCS, the test should have been secured and in-depth reviews should have been performed to determine RCS component inventories. A need for venting of the reactor head likely would have been determined.

Other conclusions made by the inspectors included weak initial support from the Technical Support organization. Specifically, a lack of system engineer knowledge of the RVLIS delayed the identification that the vessel level had actually fallen to the top of the RCS hot leg. Additionally, operators exhibited a lack of sensitivity, in that, the step change decrease in VCT temperature was not recognized or evaluated.

Regulatory Issues

The following potential regulatory issues were identified as a result of the inspectors review of the event:

1. Technical Specification (TS) 3.4.1.4 requires, in part, that two residual heat removal (RHR) loops be operable and at least one RHR loop be in operation while in MODE 5. The TS has provisions allowing the substitution of four filled reactor coolant loops for one RHR loop. However, between September 6, 1993, to December 21, 1993, one RHR loop was declared inoperable for 13 percent of that period. Subsequent to December 21, 1993, the licensee determined that four filled reactor coolant system loops were not available during the same period. This resulted in the licensee failing the enter the ACTION of TS 3.4.1.4 for the applicable periods.

2. Technical Specification Section 6.8.1 requires, in part, that procedures shall be established, implemented, and maintained covering the activities recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Appendix A of Regulatory Guide 1.33 includes administrative procedures for conduct of operations and conduct of modifications to the facility. Inherent in these requirements is that the procedures be adequate.

(a) SSP-9.3, PLANT MODIFICATIONS AND DESIGN CONTROL, Revision 6, contains specific requirements for the preparing, planning, and control of plant modifications. DCN M09505A and WO 93-09179-00 were developed under the control process guidance of SSP-9.3 to implement a modification to the Unit 1 Component Cooling System. However, DCN M09505A and/or WO 93-09179-00 were inadequate, in that, equipment modification and testing was not completed prior to returning the equipment to service. This condition resulted in an inadvertent cooldown of the volume control tank on December 1, 1993.

(b) SSP-12.1, CONDUCT OF OPERATIONS, Revision 6, paragraph 3.1.2.J.2, assigns, in part, shared responsibilities to the Unit Operator, the Operator at the Controls, and all operations personnel assigned to the control room for maintaining cognizance of plant status. However, during the period between September 6 through December 21, 1993, operators and other applicable personnel failed maintain cognizance of reactor coolant system level parameters. This resulted in the actual vessel level being at or near the top of the reactor coolant system loop piping, when the reactor coolant system was considered to be full.

3. 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action, requires, in part, that measures be established to assure that conditions adverse to quality such as failures, malfunctions, and nonconformances, are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall ensure that the cause of the condition is determined and corrective action taken to preclude repetition.

In April of 1993, an event occurred which involved an unknown loss of RCS level due to the failure of a pressurizer level indicating channel during RCS draindown evolutions. In that event, operators were not aware of a significant decrease in the RCS inventory.

In addition, other previous industry information had been available which could have alerted the licensee to the potential issue in order to preclude the event.

During the period between September 6 through December 21, 1993, a second event occurred regarding gas migration into the RCS which resulted in an unobserved RCS level decrease.

However, the licensee failed to take effective corrective actions for the April 1993 event to prevent recurrence of a similar problem involving the unknown reactor coolant system level perturbation which was identified on December 17, 1993.

4. 10 CFR 50.59 (b) (1) states, in part, that the licensee shall maintain records of changes in the facility and changes in procedures made pursuant to this section, to the extent that these changes constitute changes in the facility as described in the safety analysis report or to the extent that they constitute changes in procedures as described in the safety analysis report. These records must include a written safety evaluation which provides the bases for the determination that the change, test, or experiment does not involve an unreviewed safety question.

   However, it was determined that a safety evaluation was not performed after discovery of an unknown amount of gas accumulation in the reactor coolant system. The existence of the gas was identified during the performance of the Unit 1 CILRT on December 17, 1993. Due to the condition, the licensee revised the CILRT procedure to address the effect of the gas on the CILRT and its effect when the containment was to be depressurized from the CILRT conditions. An evaluation for the gas accumulation was not performed to address the effect of the gas on the reactor coolant system inventory. Specifically, the effect of the gas on the reactor vessel and steam generator levels was not considered.

5. 10 CFR 50, Appendix B, Criterion III, Design Control, requires, in part, that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

   However, the licensee did not establish design control measures for graph information data regarding the RVLIS contained in 0-GO-4.0, RCS DRAIN AND FILL OPERATIONS, Revision 7. This resulted in unsubstantiated information being available to operators for use during evolutions which could affect safety-related parameters.

The above issues are identified as an Apparent Violation (327/94-04-05), Inadequate Monitoring/Control of Unit 1 Reactor Vessel Inventory During Shutdown Conditions. These issues will be discussed at an Enforcement Conference with the licensee, scheduled for March 10, 1994.

Within the areas inspected, two violations and one apparent violation were identified.

9. Exit Interview

The inspection scope and results were summarized on February 10, 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
VIO 327, 328/94-04-01	Failure to Take Corrective Actions to Preclude Repetition of Configuration Control Problems.
VIO 328/94-04-02	Violation of 10 CFR 50, Appendix B, Criterion V for Failure to Provide and/or Follow procedures for Activities Affecting Quality.
VIO 327, 328/94-04-03	Violation of 10 CFR 50.59 for Failure to Perform a Safety Evaluation for a Change to the Facility as Required by Regulations.
IFI 327, 328/94-04-04	Followup on ORAT Identified Observations.
EEI 327/94-04-05	Apparent Violation for Inadequate Monitoring/Control of Unit 1 Reactor Vessel Inventory During Shutdown Conditions.

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

AFW - Auxiliary Feedwater
ASME - American Society of Mechanical Engineers
ASOS - Assistant Shift Operations Supervisor
CCP - Centrifugal Charging Pump
CCS - Component Cooling Water System
CFR - Code of Federal Regulations
CILRT - Containment Integrated Leak Rate Test
CLA - Cold Leg Accumulator
CR - Control Room
CVCS - Chemical and Volume Control System
DCN - Design Change Notice

DRP - Division of Reactor Projects
ECCS - Emergency Core Cooling System
EEI - Escalated Enforcement Issue
ERCW - Essential Raw Cooling Water
ESF - Engineered Safety Feature
FCV - Flow Control Valve
FSAR - Final Safety Analysis Report
GOI - General Operating Instruction
GPM - Gallons Per Minute
HVAC - Heating, Ventilation, and Air Conditioning
IFI - Inspector Followup Item
IM - Instrument Maintenance
IR - Inspection Report
JCO - Justification for Continued Operation
KV - Kilovolt
LCO - Limiting Condition for Operation
LCV - Level Control Valve
LDHX - Letdown Heat Exchanger
LER - Licensee Event Report
MOV - Motor Operated Valve
MRC - Management Review Committee
MRRC - Management Restart Review Committee
MSIV - Main Steam Isolation Valve
NOT - Normal Operating Temperature
NOUE - Notification of Unusual Event
NRC - Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation
ORAT - Operational Readiness Assessment Team
PCV - Pressure Control Valve
PER - Problem Evaluation Report
PMT - Post Maintenance Test
PORV - Power Operated Relief Valve
PSIG - Pounds Per Square Inch
RCP - Reactor Coolant Pump
RCS - Reactor Coolant System
RHR - Residual Heat Removal
RII - NRC Region II
RVLIS - Reactor Vessel Level Indication System
RWP - Radiation Work Permit
SG - Steam Generator
SI - Surveillance Instruction
SO - System Operations
SOI - System Operating Instruction
SQ - Sequoyah
SS - Stainless Steel
SSP - Site Standard Practice
TAVE - Average Temperature of the Reactor Coolant System
TCV - Temperature Control Valve
TI - Temperature Indication
TS - Technical Specifications
TSV - Temperature Solenoid Valve
URI - Unresolved Item

VCT	-	Volume Control Tank
VIO	-	Violation
WO	-	Work Order