NOV 1 7 1995

Tennessee Valley Authority
ATTN: Mr. Oliver D. Kingsley, Jr.
President, TVA Nuclear and
Chief Nuclear Officer
6A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: NRC INSPECTION REPORT NOS. 50-327/95-21 AND 50-328/95-21

Dear Mr. Kingsley:

This refers to the inspection conducted on October 1 through October 28, 1995, at the Sequoyah facility. The purpose of the inspection was to determine whether activities authorized by the license were conducted safely and in accordance with NRC requirements. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed report.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observation of activities in progress.

Within the scope of the inspection, one additional example of the violation cited in Inspection Report 50-327, 328/95-20 was identified. As discussed with you at the exit, you agreed to include this additional example in your response to the cited violation.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and any response will be placed in the NRC Public Document Room (PDR).

Sincerely,

Original Signed by
M. S. Lesser

Mark S. Lesser, Chief
Reactor Projects Branch 6
Division of Reactor Projects

Docket Nos. 50-327, 50-328
License Nos. DPR-77, DPR-79

Enclosure: (See page 2)

IE01

Enclosure: Inspection Report

cc w/encl:

Mr. O. J. Zeringue, Senior Vice Pres.
Nuclear Operations
Tennessee Valley Authority
3B Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

Dr. Mark O. Medford, Vice Pres.
Engineering & Technical Services
3B Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

Mr. D. E. Nunn, Vice Pres.
New Plant Completion
Tennessee Valley Authority
3B Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

Mr. R. J. Adney, Site Vice Pres.
Sequoyah Nuclear Plant
Tennessee Valley Authority
P. O. Box 2000
Soddy Daisy, TN 37379

General Counsel
Tennessee Valley Authority
ET 11H
400 West Summit Hill Drive
Knoxville, TN 37902

Mr. P. P. Carier, Manager
Corporate Licensing
Tennessee Valley Authority
4G Blue Ridge
1101 Market Street
Chattanooga, TN 37402-2801

Mr. Ralph H. Shell
Site Licensing Manager
Sequoyah Nuclear Plant
Tennessee Valley Authority
P. O. Box 2000
Soddy Daisy, TN 37379

TVA Representative
Tennessee Valley Authority
Rockville Office
11921 Rockville Pike
Suite 402
Rockville, MD 20852

Mr. Michael H. Mobley, Dir.
Div., of Radiological Health
3rd Floor, L and C Annex
401 Church Street
Nashville, TN 37243-1532

County Judge
Hamilton County Courthouse
Chattanooga, TN 37402

Ms. Ann Harris
305 Pickel Road
Ten Mile TN 37880

Distribution w/encl: (See page 3)

Distribution w/encl:
E. W. Merschoff, RII
M. S. Lesser, RII
S. E. Sparks, RII
F. J. Hebdon, NRR
D. E. LaBarge, NRR
Document Control Desk

NRC Resident Inspector
U. S. Nuclear Regulatory Commission
2600 Igou Ferry
Soddy-Daisy, TN 37379

NRC Resident Inspector
U. S. Nuclear Regulatory Commission
1260 Nuclear Plant Road
Spring City, TN 37381

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Results:

An additional example of the violation identified in inspection report 327, 328/95-20 for failure to follow and/or provide adequate controls for the clearance process as described in Site Standard Practice-12.3 was identified (paragraph 3.c).

In the area of Operations, very good performance was observed. Examples were: high level of nuclear safety sensitivity during Unit 1 refueling evolutions, very good sensitivity to Unit 2 operations, very good response to the Unit 1 #4 reactor coolant pump (RCP) seal leakoff high flow condition, and very good reduced inventory operation. Other observations included lower thresholds for identification of issues and good management sensitivity to address the clearance problem in a Plant Operations Review Committee meeting. Weak areas observed were the additional example of a clearance problem referenced above, and less than thorough Management Review Committee Problem Evaluation Report review activities (paragraph 3).

In the area of Maintenance, good performance was observed. Examples were: maintenance activities associated with the corrective action for a CS CCS (normal B train component cooling system) pump seal leak, Unit 1 steam generator chemical cleaning/inspection activities, and repair of a bent instrument thermocouple column (paragraph 4). One weak area associated with an Arrow-Hart starter failure was observed (paragraph 6.a). Surveillance activities associated with the Unit 1, B train Residual Heat Removal (RHR) pump and the CS CCS pump were performed in a good manner (paragraph 5).

In the area of Engineering, very good performance was observed. Examples were: engineering support for CS CCS pump maintenance (paragraph 4), new design of starter buckets for Unit 1 480 volt motor operated valve (MOV) boards, monitoring activities associated with auxiliary feedwater (AFW) pumps, and technical support for evaluation of radiation monitor sample line moisture problems (paragraph 6).

In the area of Plant Support, good performance was observed. Examples included ALARA (As Low As Reasonably Achievable) performance in achieving the person-rem and personnel contamination events Unit 1 outage goals for original outage scope of work. However, increased scope of outage activities due to emerging work resulted in increased dose (paragraph 7). Also, one issue associated with poor attention to detail during placement of the reactor vessel head resulted in additional dose during the evolution (paragraph 4.d).

REPORT DETAILS

1. **PERSONS CONTACTED**

Licensee Employees

*R. Adney, Site Vice President
*J. Baumstark, Plant Manager
*D. Brock, Maintenance Manager
*L. Bryant, Outage Manager
*M. Burzynski, Engineering & Materials Manager
*M. Cooper, Technical Support Manager
R. Driscoll, Nuclear Assurance & Licensing Manager
*F. Fink, Business and Work Performance Manager
*T. Flippo, Site Support Manager
G. Enterline, Operations Manager
C. Kent, Radcon/Chemistry Manager
*W. Lagergren, Manager of Projects
*L. Poage, Site Quality Assurance Manager
R. Rausch, Maintenance and Modifications Manager
J. Reynolds, Acting Operations Superintendent
*J. Robertson, Independent Analysis Manager
*R. Shell, Site Licensing Manager
*N. Welch, Operations Superintendent

NRC Employees

*W. Holland, Senior Resident Inspector
*D. Seymour, Resident Inspector
*R. Starkey, Resident Inspector

*Attended exit interview.

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

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

2. **PLANT STATUS**

Unit 1 began the inspection period defueled (day 23 of the Unit 1 Cycle 7 refueling outage). During this period, Unit 1 entered MODE 6 on October 2 and completed core reload on October 5, 1995. On October 7, during lowering of the reactor vessel head, a instrument thermocouple column was bent requiring the head to be removed. This event is further discussed in paragraph 4.d. After corrective actions were accomplished, reactor reassembly continued and Unit 1 entered MODE 5 on October 15, 1995. After completion of appropriate outage activities, Unit 1 entered

MODE 4 on October 24, and MODE 3 on October 26, 1995. However, during RCS heatup and pressurization, high seal leakage was observed on RCP #4 on October 28. This condition is further discussed in paragraph 3.a.(3). Unit 1 was cooling down to MODE 5 for repairs to the #4 RCP seal (day 50 of the Cycle 7 refueling outage) when the inspection period ended.

Unit 2 began the inspection period in power operation. The unit operated at power for the duration of the inspection period.

3. **PLANT OPERATIONS** (71707 and 92901)

a. Daily Inspections

The inspectors conducted selective examinations, on a day-to-day basis, which involved control room tours, plant tours, and management meetings. The following activities were specifically reviewed:

(1) Unit 1 Refueling Evolutions

Early in the period, the inspectors monitored refueling activities for Unit 1. Specific observations were made for fuel handling evolutions in the Unit 1 reactor building and in the area of the spent fuel pool. The core was reloaded in approximately 67 hours. During this period, the operators experienced some problems associated with manipulator crane operation. The inspectors reviewed the problems with operations personnel including the refueling SRO and determined that a high level of nuclear safety sensitivity was being maintained during the period that the manipulator crane problem was being addressed.

Subsequent to refueling, the inspectors reviewed a completed copy of FHI-3, MOVEMENT OF FUEL, Revision 28. The inspectors noted that limit switch bypasses to address equipment problems were logged as required. No discrepancies were noted in the FHI documentation.

The inspectors concluded the refueling of Unit 1 between October 2 and October 5, 1995 was accomplished in a good manner with a high level of nuclear safety sensitivity being demonstrated by the fuel handling SROs and other personnel involved in the evolutions.

(2) Operator Sensitivity to Unit 2

During the last two months, the inspectors focused additional attention to operation of Unit 2. The inspectors wanted to ensure that appropriate attention was focused on the operating unit during the Unit 1 outage. Reviews of shift turnover activities and the operational demeanor of ROs and AUOs for Unit 2 indicated good sensitivity to plant conditions and identification of problems requiring maintenance or other activities to correct. In addition, review of plant personnel response to a protection channel card failure on Unit 2, on October 17, 1995, demonstrated excellent teamwork between operations, maintenance, and engineering in evaluating and correcting a problem which could have placed continued reliable operation at risk.

The inspectors concluded that operator sensitivity to Unit 2 operations during the Unit 1 outage was very good. Good safety sensitivity was observed during shift turnovers and during routine unit operations.

(3) Unit 1 RCP #4 Seal Leakoff Flow High

On October 28, 1995, at approximately 5:30 a.m., Unit 1 was operating in MODE 3, RCS temperature approximately 430 °F, and raising RCS pressure (pressure at the time was approximately 1240 psi). Operators received a #4 RCP seal leakoff flow high alarm (4.8 gpm) and took appropriate actions to address the condition in accordance with Abnormal Operating Procedure AOP-R.04, REACTOR COOLANT PUMP MALFUNCTIONS, Revision 0. During the next hour, operators stopped the #4 RCP, isolated the #1 seal leakoff flowpath, and depressurized the Reactor Coolant System to approximately 600 psi.

The inspectors were notified of the abnormal condition by the operators and reported to the plant. The inspectors were briefed by plant management, reviewed the AOPs and the operators response to the occurrence, observed licensee activities associated with preparing a troubleshooting plan, and reviewed actual plant conditions. The inspectors concluded that initial operator response to the #4 RCP seal leakoff high flow condition was very good. In addition, plant staff planning, troubleshooting, and development of an action plan to resolve the abnormal condition was methodical and demonstrated a very good safety sensitivity to addressing the problem.

b. Biweekly Inspections

The inspectors conducted biweekly inspections, using the licensee's IPE information, to verify operability of the following ESF trains.

The inspectors reviewed the licensee's outage risk assessment of the modification of the 1A-A EDG. The licensee implemented an EPRI computer program, ORAM (Outage Risk Assessment and Management), which incorporated generic shutdown risk studies performed by EPRI. This computer model is not PRA/IPE based. On a daily basis, the licensee imports their outage schedule, including early start and finish dates, into ORAM. ORAM generates a Safety Function Status Report that is divided into seven key areas: reactivity control, shutdown cooling, inventory control, fuel pool cooling, electrical power control, containment, and vital support systems.

Based on the imported schedule and overlaps of scheduled activities, these key areas will either be reported as green, yellow, orange or red. Green is defined as fully adequate, defense in depth present, minimal risk; yellow is defined as meets defense in depth, but at slightly reduced minimal risk; orange is defined as at TS minimum required without high risk evolution potential, and requires review by the Outage Management Team and/or the SOS; and red is defined as at TS minimum requirement with high risk evolution potential, or less than TS requirements. A red result is considered by the licensee as extremely high risk. The licensee stated that activities are rescheduled to avoid this risk when a red result is obtained.

The inspectors noted that scheduling the 1A-A EDG modification caused an orange report condition for shutdown cooling. The inspectors reviewed the decision train for shutdown cooling and noted that one unavailable EDG automatically placed shutdown cooling into the orange risk category, and that the Outage Management Team had reviewed the activity.

The inspectors concluded, based on this review, that ORAM was a good tool for assessing, controlling, and managing evolutions which presented outage risk.

c. Monthly Inspections

During the inspection period, the inspectors became aware of a clearance issue documented in PER SQ951915 through observation of a PORC meeting, held on October 24, 1995. Based on observation of PORC meeting discussions, the inspectors were initially concerned that inappropriate focus was directed in the Maintenance area during the PORC meeting. The issue was identified when Operations attempted to place the Unit 1 glycol floor coolant system in service on October 24, and discovered that the floor coolant coils were isolated. This system provides cooling capacity to the ice condenser via a single inlet and outlet line into containment, which then splits off into various branches imbedded in the containment floor. After the initial discovery, AUOs were dispatched to realign the floor coolant coils using the appropriate valve checklists, and identified that 7 valves were mispositioned. In response, Operations conducted a walkdown of various equipment potentially affected by any clearance issued since the completion of a system alignment valve checklist (20 total), and verified that no additional components were misaligned.

Review of the appropriate documentation noted that a clearance was issued on September 28, 1995, to replace flex hoses per work order 93-02283-00. During this maintenance activity, maintenance personnel found it necessary to manipulate additional throttle valves in the various branches. The work order indicated that the valves were documented closed between the dates of October 4-15, however, the valves were not returned to normal by maintenance personnel. Thus, maintenance personnel failed to follow the requirements of SSP-6.24. Based on discussions with Operations personnel and a review of SSP-12.3, EQUIPMENT CLEARANCE PROCEDURE, Rev. 10, the inspectors also noted that the requirements of SSP-12.3 were not followed regarding releasing a clearance. Specifically, Section 3.2.6.B.5 requires the SOS/Representative maintain configuration control when releasing a clearance by utilizing either (1) the entire valve/power checklist, or (2) the Restoration Check Sheet, Appendix D, to SSP-12.3. Discussion with licensee personnel indicated that the SOS/SOS Representative mistakenly assumed that a previously performed Ice Condenser Cooling Valve Checklist 1-61-1.02 was performed after the completion of the maintenance activity. As such, the clearance was lifted without performance of the valve checklist, and resulted in a failure to maintain configuration control.

The inspectors considered this issue to be an additional example of a violation issued in IR 327, 328/95-20, in which the licensee failed to properly implement the requirements of SSP-12.3. The inspectors requested the licensee's response to violation 327, 328/95-20-01 also address this latest clearance issue.

The inspectors considered the licensee's decision to hold a PORC meeting to be an indicator of appropriate sensitivity to this issue. In addition, the licensee's initial response to verify that a configuration control issue did not exist was good. Management representatives from maintenance and operations displayed appropriate sensitivity to NRC concerns, and activities in response to the PER process in the maintenance and operations areas appeared to be properly focused. The inspectors also held discussions with an on-shift ASOS and a Unit Manager, who displayed a clear understanding of Operations responsibility in the clearance process. In addition to these activities, the licensee was conducting additional reviews of recent clearance process issues. These activities, as well as activities in response to this latest clearance issue, will be reviewed during closeout of violation 327, 328/95-20-01.

d. Trimonthly Inspections

During this period, the inspectors reviewed the use of overtime by Operations department personnel between September 3, and October 15, 1995. Records were reviewed and overtime management oversight was discussed with plant management personnel. Finally, the inspectors discussed overtime usage with selected operators (SROs, ROs, and AUOs).

The inspectors determined, based on these reviews, that overtime was being managed as required. Increased use of overtime was noted for several operators supporting the Unit 1 outage; however, other Unit 1 operators and those on Unit 2 generally were working less overtime than in the past. Several examples were identified where operations personnel were working up to 16 hour shifts in support of outage activities. A sample of documentation of overtime for selected individuals indicated that the licensee was adhering to administrative and TS requirements. The inspectors concluded that Operations overtime usage for the periods reviewed was being managed as required by regulations.

e. Semi-Annual Inspections

On October 20, 1995, the inspectors observed a portion of the performance of 0-SI-ICC-052-082.0, CHANNEL CALIBRATION OF TRIAXIAL PEAK ACCELERATION (SEISMIC) RECORDER XR-52-82, XR-52-83, XR-52-84, Revision 2. This was an 18 month calibration which met the requirements of TS 4.3.3.3.1 and 4.3.3.3.2. The inspectors concluded from their observation of the calibration process that the calibration was conducted in accordance with the surveillance instruction.

f. Outage Inspections

Reduced Inventory Operations - Unit 1

During this period, prior to reduced inventory operations, the inspectors reviewed the licensee's preparations for operation in reduced inventory and midloop conditions. Operation in these conditions was required in order to remove SG nozzle dams which had been installed earlier in the outage with the vessel defueled. The inspection included review of the licensee's response to Generic Letter 88-17, Loss of Decay Heat Removal, along with implemented actions based on that response. The specific items reviewed before and during reduced inventory and midloop operations were:

- Administrative Controls - The inspectors discussed, with personnel from the licensee's training organization, the special training received by the operations crews in preparation for the Unit 1 Cycle 7 outage. This training included Mansell Level Gauge operation, solid water operation, vacuum refill operations, and air bubbling of the SG during draining. The inspectors also reviewed the operator training package used for license requalification that included a review of midloop operations, and a simulator scenario in which RHR was lost due to pump cavitation.

On October 18 and 19, 1995, the inspectors attended crew briefs for reduced inventory operations. The inspectors considered the briefs covered reduced inventory and midloop operations in a thorough and comprehensive manner.

The inspectors reviewed applicable portions of procedure 0-GO-13, REACTOR COOLANT SYSTEM DRAIN AND FILL OPERATIONS, Revision 1; procedure SSP-12.2, SYSTEM AND EQUIPMENT STATUS CONTROL, Revision 15; procedure 0-TI-OXX-068.001.0, BREACHING CONTAINMENT OR THE REACTOR COOLANT SYSTEM DURING UNIT OUTAGES, Revision 6; and procedure SOI-88.1, CONTAINMENT ISOLATION SYSTEM, Revision 36. 0-GO-13 provided guidance and directives for plant operations during RCS drain down and refilling. Sections 5.1.2 and 5.1.3 provided the instructions for RCS drain operations to reduced inventory conditions and to midloop conditions, respectively. Minor procedural discrepancies in 0-GO-13 were identified by the inspectors regarding reference to the elevation of the reactor vessel flange. These discrepancies were corrected prior to reduced inventory operations.

- Containment Closure Capability - 0-GO-13, Section 5.1.2, step [11] included directions to ensure configuration control is in accordance with procedure SSP-12.2. SSP-12.2, Section 3.9 provided guidelines for maintaining containment closure when in modes 5 or 6 with fuel in the vessel. SSP-12.2 referenced SOI-88.1. SOI-88.1, Section 88.1D, provided instructions and methods for controlling containment barriers during reduced inventory/midloop operations for compliance with containment closure guidance of Generic Letter 88-17.

  0-GO-13 also referenced 0-TI-OXX-068-001.0. This procedure provided the requirements for controlling breaches to the containment during refueling to ensure the breaches could be closed if RHR cooling was lost. The inspectors verified that the TI was properly implemented.

- RCS Temperature - The inspectors verified that 0-GO-13, Section 5.1.2, Step [12] required at least two RCS incore thermocouples be operable, and that RCS temperature is tracked and recorded. 0-PI-IXX-068-001.0, REACTOR HEAD INSTRUMENTATION REMOVAL AND REINSTALLATION, Revision 6, delineated acceptable combinations of core exit thermocouples, and provided the instructions for changing the setpoints for these thermocouples. 0-TI-OXX-068-001.0, Section 3.0, Precautions and Limitations, Subsection 3.2.A.4, Reduced Inventory or Midloop, required that two exit thermocouples be connected when the reactor head is on the vessel with visible and audible alarms in the MCR. The inspectors verified that exit thermocouples were operable during reduced inventory operation.

- RCS Level Indication - The inspector verified that 0-GO-13, Section 5.1.2, Step [4] through [6], required at least two RCS level indicators in service, and that level is tracked and recorded. The inspector discussed the liquid level gauge, the Mansell Level Monitor, the sightglass, and the ultrasonic level measurement system with the operators in the CR. The inspector verified, through discussions with the licensee that level instrumentation was in agreement with required tolerances.

  0-GO-13, Section 5.1.3, required at least two level indications to be operable, and provided detailed instructions on tracking level while draining RCS to midloop. 0-TI-OXX-068-001.0, Section 3.0, Precautions and Limitations, Subsection 3.2.A.1, Reduced Inventory or Midloop, required that level indicating systems must be maintained available in accordance with 0-GO-13. The inspectors monitored actual level indications during reduced inventory operations, and verified consistency between different indications.

- RCS Perturbations - The inspectors verified that 0-GO-13, Section 5.1.2, Step [11] [g], required the outage management team manager to ensure outage activities would not deliberately or knowingly lead to perturbations in the RCS system. If activities were required to be worked, Operations must establish controls in accordance with 1,2-PI-OPS-068-673.D, DAILY REQUIREMENTS FOR REDUCED INVENTORY/MIDLOOP OPERATION, Revision 2. The only outage activities worked which could affect RCS level were nozzle dam removal and vacuum fill of the RCS. Vacuum fill of the RCS was controlled in accordance with 0-GO-13, Section 5.3.4.

- RCS Inventory Addition - The inspector verified that 0-GO-13, Section 5.1.2, Step [14], required the operator to ensure that 1,2-PI-OPS-068-673.D, had been completed. 1,2-PI-OPS-068-673.D required the operator to verify at least two of several listed emergency makeup flowpaths were operable and/or available. 0-TI-OXX-068-001.0, Section 3.0, Precautions and Limitations, Subsection 3.2.A.2, also required a minimum of two water supply sources be available. The inspectors verified that charging pumps, safety injection pumps, and gravity feed from the RWST (when applicable) were available to perform this function during reduced inventory operations.

- Nozzle Dams - The licensee used nozzle dams during inspection and repair of steam generator tubes during the refueling outage. The nozzle dams were installed after the reactor vessel was defueled. During reduced inventory operation with nozzle dams installed, the licensee established a vent path through the pressurizer via two openings where code safety valves had been removed. The inspectors verified these vent paths were maintained during reduced inventory operations until the nozzle dams were removed. In addition, a hot leg vent path was maintained until all cold leg openings were closed.

- Contingency Plans to Repower Vital Busses - 0-TI-OXX-068-001.0, Section 3.0, Precautions and Limitations, Subsection 3.2.A.6 stated, that to minimize loss of power, both trains of EDGs and two offsite power sources shall be available. Subsection 3.2.D further required control of switchyard activities to be maintained during reduced inventory/midloop in accordance with NS-MI-114, Instructions For Access To The Switchyard During Mid-Loop. The inspectors verified required power sources were maintained and appropriate switchyard controls were in place during reduced inventory operations.

The inspectors noted that the licensee provided good management oversight of reduced inventory/midloop operations during this period. RCS reduced inventory was considered a CIPT evolution with an assigned CIPT manager for the reduced inventory operations period. Unit 1 entered a reduced inventory condition on October 18, at 11:00 p.m., and exited a reduced inventory condition on October 21, at 6:05 a.m. The inspectors concluded that the licensee preparation and control of reduced inventory operations was accomplished in a very good manner. Operations briefings were especially noteworthy.

g. Effectiveness of Licensee Controls

During this period, the inspectors attended most of the MRC meetings. The meetings were held on Mondays, Wednesdays, and Fridays, and lasted approximately 1 hour. A major purpose of the meeting was for licensee senior management to review status of PER activity. The inspectors noted specific MRC focus was on level A and B PERs to assure that appropriate department attention was placed on safety significance, reportability determinations, and ownership of issues. The inspectors noted the PER threshold for identification of issues at the plant had decreased, resulting in more C and D level PERs in the last two months. This increase in PERs was considered a positive indicator of licensee sensitivity to identification of problems.

However, the inspectors also noted, on occasion, that the MRC did not probe issues to fully understand if the PERs were being dispositioned in the proper manner. In addition, observations indicated that limited MRC knowledge of PER issues resulted in less than fully effective overviews of the process. Examples noted were discussions associated with PERs written for a leak on a containment spray isolation valve, a problem associated with a radiation monitor pump, and switchyard control issues prior to reduced inventory operations.

On October 26, 1995, the licensee provided the inspectors with feedback as to the purpose of MRC overview of issues at MRC meetings. They noted that confusion sometimes arises in MRC meetings regarding the specific details of reviewed issues. Licensee senior management stated this condition will be solved by bringing the personnel with the knowledge of the issue to the MRC to explain the circumstances of the issue.

The inspectors concluded the licensee's corrective action process was working better in identification of issues (PER threshold was lower); however, the MRC PER review activities were not always thorough and sometimes limited MRC knowledge of the issues resulted in less effective overview of this corrective action process. Senior management was taking actions to address this area.

h. Licensee NRC Notifications

On October 14, 1995, the licensee made a call to the NRC as required by 10 CFR 50.72. The issue involved a licensee contractor worker being transported off-site for medical treatment of a contaminated cut to his left hand. The cut occurred during work on a Unit 1 steam generator. During maintenance on the steam generator, the individual's hand was cut when a steam generator tube cut through his protective clothing. The individual was decontaminated to approximately 1000 counts per minute prior to transport off-site. Additional decontamination efforts over the next several days resulted in decontamination of the cut to levels which allowed for release of the contractor.

i. Followup reviews were accomplished during the inspection period for the following items:

(Closed) VIO 327, 328/95-08-02, Failure to perform and document prerequisites and NOTES in accordance with procedures, error in drawing 91934-7355A, and failure to provide adequate instructions as part of work order 94-01658-OC during performance of the spent fuel pool rerack project. The issues involved several procedural requirements not being followed during the subject project. In addition, work order inadequacies were identified and a drawing deficiency resulted in a dummy fuel assembly not clearing the spent fuel pool storage rack prior to movement. The licensee responded to the violation in a letter to the NRC dated May 30, 1995. The letter identified the root cause of the violation items as insufficient understanding and commitment to the rerack project by senior management.

Corrective actions for specific issues included better communication of management's expectations to both fuel handling supervisors and shift operations supervisors, work planners, and engineers. As a result of better management sensitivity, the rerack project was successfully completed without further events.

The inspectors reviewed the licensee's corrective actions, monitored selected rerack project activities until the project was complete, and verified that administrative procedures were enhanced to specifically address work order review requirements.

Within the areas inspected, an additional example of a violation cited in inspection report 327, 328/95-20 was identified.

4. **MAINTENANCE OBSERVATIONS** (62703 and 92902)

During the reporting period, the inspectors verified by making observations, conducting reviews, and interviewing maintenance personnel, that the licensee's maintenance activities result in reliable operation of plant safety systems and components, and are performed in accordance with regulatory requirements. Inspection areas included the following:

a. Late in the last inspection period, the CS CCS pump experienced two problems requiring significant corrective maintenance. The CS CCS pump is the normal B-TRAIN pump in operation for the component cooling system. The first problem, identified on September 26, 1995, involved a high packing leak rate for the CS pump requiring the pump to be secured. The second problem involved the CS pump 480 volt breaker. Operators attempted to stop the pump from the control room; however, the pump breaker could not be tripped remotely. Operators were dispatched to trip the breaker locally (480 volt Shutdown Board 2B2-B). However, initial attempts to trip the breaker locally were unsuccessful. The breaker was finally tripped using a mechanical device. Subsequent checkouts of the breaker identified a failed trip coil. PER SQ951658 was written identifying the excessive packing leakage problem for the CS pump. PER SQ951659 was written identifying the breaker failure for the CS pump. Both PERs were assigned to the Component Engineering Group for resolution.

   During this period, the inspectors commenced a review of maintenance activities and corrective actions associated with the two problems identified for the CS CCS pump. Work request C210544 was written to initiate maintenance activities to correct the high pump seal leakage problem. WO 95-11061-00 planned and implemented the maintenance activities to refurbish the pump. Corrective actions for this condition included: disassembly and removal of the pump rotating element, refurbishment of the pump shaft sleeves, and reassembly of the pump.

The inspectors monitored selected pump maintenance activities in the plant and reviewed the completed work package. They noted the package was concise and included clear notes on actual work performed. However, two problem areas noted by the inspectors during field observations were not discussed in the work package. These areas were: pump casing reassembly techniques and pump seal problems after initial pump checkouts.

On October 16, 1995, the inspectors discussed these issues with the licensee maintenance and engineering personnel. The inspectors were informed that the work documentation should have addressed the inspector's observations. In addition, component engineering personnel were reviewing the lessons learned on the maintenance activity to address improvements on the other CCS pumps. Maintenance management indicated this feedback would be factored in future activities. Testing of the pump after maintenance s discussed in paragraph 5.b. Review of the pump breaker problem is discussed in paragraph 4.b.

The inspectors concluded that the CCS pump maintenance activity was accomplished in a good manner, with the exception of the two minor observations discussed above. In addition, maintenance and component engineering focus on lessons learned for this activity have been captured for future pump overhauls.

b. On September 26, as discussed in paragraph 4.a, operators attempted to stop the CS CCS pump by taking the MCR hand switch to the pull-to-lock position; however, the pump continued to run. An operator was then dispatched to the 480V shutdown board to manually trip the pump breaker (Westinghouse type DS-206 circuit breaker). Several repeated attempts were made before the breaker was manually tripped using a socket head screwdriver to forcefully depress the manual trip push button. The breaker was subsequently taken to the electrical shop for troubleshooting. The licensee determined that the breaker shunt trip coil had burned up, apparently due to being continuously energized during its attempt to trip the breaker. During the troubleshooting process, the breaker was cycled numerous times but the failure to trip could not be duplicated.

The licensee initially believed that the failure of the breaker to trip was caused by a sticky lubricant found on the main drive link and its roller. A laboratory analysis identified the substance as part of the main drive link roller sleeves and concluded that the substance was designed into the bearing of the roller. The licensee also questioned the vendor as to whether additional lubricant should have been added periodically to the roller bearing. The vendor stated that no additional lubricant should be applied to the roller portion of the mechanical trip mechanism.

To assist in the evaluation of the failed breaker, a Westinghouse breaker expert spent approximately two days on site inspecting, analyzing and evaluating the breaker. The vendor concluded that (1) the failed breaker was found in good condition, (2) no single cause was found for the failure to trip, and (3) the most probable cause for the failure was a combination of higher than normal friction in various points of the linkage and trip mechanism and less than the maximum opening force from the A and B phase pole base opening springs. Based on their testing and the vendor's evaluation, the licensee concluded that the CS CCS breaker had experienced a random failure.

The licensee also researched the maintenance history of the failed breaker and discovered the following. In October, 1994, a routine MI-10.5, 480-V WESTINGHOUSE DS SWITCHGEAR INSPECTION, was performed on the CS CCS pump breaker (in 1992, MI-10.5 had incorporated the recommendations of Westinghouse Technical Bulletin NSD-TB-91-06-RO, DS-206 AND DSL-206 BREAKERS-MECHANICAL FRICTION OF MAIN CONTACT ASSEMBLIES). In April, 1995, the breaker failed to trip via the MCR hand switch. There was no documentation in the April work package which indicated that the breaker was binding at the time of its failure or that maintenance personnel checked for that possibility. The shunt trip coil was replaced and the breaker was returned to service. The breaker remained in service until it again failed to trip on September 26, 1995. The licensee also conducted a historical search for safety related DS breakers which had previous shunt trip coil failures. Ten breakers were identified. Of those ten breakers only three had not had procedure MI-10.5 performed since their respective failures.

Although the licensee considered the CS CCS pump breaker failure to be random, several corrective actions were recommended when the vendor was on site. These actions were: (1) revise MI-10.5 to add Westinghouse suggested enhancements (ensure roller rolls freely, roller alignment to cam check, increase the sensitivity of contact adjustment and insulator alignment), (2) perform complete refurbishment of the failed CS CCS breaker before reinstallation or stored as a spare and, (3) perform MI-10.5 on the remaining three breakers which had previous shunt trip coil failures.

The inspectors discussed the failed breaker with licensee maintenance and engineering personnel and also observed testing of the breaker in the electrical shop. The inspectors were initially concerned that other DS-206 breakers at Sequoyah could be subject to the same type failure. The licensee did not believe that other breakers were affected since this failure was evaluated as random. The inspectors were also concerned that the failure could represent an industry wide problem. A similar industry problem was identified in 1992 with the issuance of NRC IN 92-44: PROBLEMS WITH WESTINGHOUSE DS-206 AND DSL-206 TYPE CIRCUIT BREAKERS. A review of IN 92-44 identified that the problem experienced on September 26, 1995 was similar to the breaker problems discussed in the IN.

The inspectors concluded that the licensee conducted an adequate investigation to determine the possible cause of the breaker failure, and to implement appropriate preventative maintenance actions on other suspect breakers.

c. Steam Generator Chemical Cleaning/Inspection Activities.

During the Unit 1 Cycle 7 outage, the licensee conducted chemical cleaning and sludge lancing evolutions on the secondary side of the four steam generators. These processes were employed to remove impurities which could degrade heat transfer in the SGs over time. During the chemical cleaning evolutions on SG #4, the licensee discovered a through-wall leak at the tube support plate dented intersection for the tube located at Row 2, Column 13. Eddy current testing subsequently confirmed the tube condition. The licensee determined that pulling this tube was an excessive risk due to the tube location, crack location, and concern of producing a loose part condition. In accordance with procedures, the tube was plugged.

The licensee also conducted SG tube inspections as required by TS surveillance requirement 4.4.5.2. The licensee's SG examinations resulted in the classification of SGs #2, #3, and #4 as category C-3, consistent with TS surveillance requirement 4.4.5.2 and Table 4.4-2.

Several discussions were held between the licensee staff, NRR staff and NRC Region II personnel, regarding activities associated with SG tube examinations. The NRC noted that a larger number of tube cracks were found during this outage compared with previous outages and attributed this to improved examination techniques and equipment, improved training, cleaner tubes resulting from the chemical cleaning procedure described above, the chemical cleaning procedure itself, and normal wear.

Based on these discussions, the NRC concluded the licensee used a very aggressive program to inspect SG tubes, was very responsive to NRC staff concerns and questions, and followed all relevant guidelines in the evaluation of SG tube indications. In addition, the licensee showed initiative when special equipment and time was used to remove a tube that was especially difficult to remove. In total, 164 tubes (as compared to 37 the previous outage) were plugged and 3 tubes were removed. The NRC also concluded that the licensee's SG examination program was acceptable for restart of Unit 1; however, the staff indicated to the licensee the need to evaluate the appropriate interval between inspections as a result of several indications which could potentially not withstand the pressure loadings specified in Regulatory Guide 1.121. An additional meeting between TVA and NRC is being scheduled to discuss this issue.

During the SG tube inspections, TVA discovered that a tube had not been properly dispositioned during the previous outage. As a result a tube was not plugged that met the technical specification plugging criteria. During the operating cycle the tube did not develop a leak. TVA determined that this was an isolated event and was caused by misjudgement on the part of the primary and secondary analyst (See LER 50-327/95-014).

d. Bent Instrument Thermocouple Column Repair

On October 7, 1995, during lowering of the Unit 1 reactor vessel head, one of the instrument thermocouple columns attached to the upper internals was bent. The column was bent when a reactor vessel head guide funnel failed to pass the instrument column through the head penetration. Upon discovery of the bent column, the reactor vessel head was removed and returned to its stand. An investigation to determine the cause of the problem was initiated and the licensee and Westinghouse began to mobilize a maintenance team to repair the bent column.

The inspectors were notified of the problem and reported to the site to review licensee activities. The RCS level was approximately one foot below the vessel flange during the event. The licensee was taking adequate precautions to assure shutdown cooling was being maintained during this timeframe. The inspectors obtained a copy of PER SQ951759 and discussed the problem with outage management. The inspectors also reviewed a video tape of the lowering of the head and the observations recorded involving the bent instrument thermocouple column.

The inspectors continued with their review of licensee repair activities on October 8. They noted the instrument thermocouple column was bent in two locations. The first location, a few inches above the upper internals, appeared to be bent approximately 20 degrees from vertical. The second location, at the point where a temporary section of the column is attached, appeared to be bent approximately 40 to 50 degrees. Review of video tape taken for the funnel on the head indicated that the tip of the column came in contact with the edge of the funnel when the head was lowered. This condition resulted from an alignment problem greater than the allowed tolerance.

The licensee instituted corrective actions over the next few days to straighten the bent thermocouple column. Activities were accomplished using appropriate vendor procedures. The inspectors reviewed the licensee's procedures and safety assessments and determined they were adequate to accomplish the activities.

On October 12, 1995, the inspectors monitored licensee activities associated with landing of the reactor head on the vessel. The inspectors noted that the effort involved personnel in the cavity assuring proper alignment of thermocouple columns and jackshafts. No alignment problems were experienced with the thermocouple columns or jackshafts. However, during the head movement evolution, the inspectors noted that some difficulty was experienced in aligning the head with the head guide pins. This difficulty resulted in a person going into the cavity for about 20 minut to observe head/guide pin alignment from that vantage point. After the 20 minute period, the person came out of the cavity and additional discussions were held regarding head/guide pin alignment. A polar crane move was made to assure proper head positioning, and the head was then landed on the vessel with no additional problems. The inspectors noted that the person in the cavity for 20 minutes on the first attempt received approximately 425 millirem radiation dose.

After discussing this issue with the licensee, the inspectors noted the head/alignment problem was associated with minor head movements and possible initial positioning variances. The inspectors discussed this observation with licensee personnel and were informed that the crane operators did not consider that the crane was in the correct position during the first attempt. However, the person in charge of the evolution decided the position was close enough and the head landing was attempted. After the unsuccessful attempt, the polar crane was moved a few inches and the head was relanded. The inspectors considered that the first attempt to land the head caused unnecessary exposure to licensee personnel. The inspectors stated they considered the exposure was not ALARA for the evolution.

The inspectors concluded the corrective maintenance activities to straighten the bent thermocouple column were accomplished in a good manner. In addition, proper verification of thermocouple columns and jackshafts alignments was accomplished. However, one issue associated with poor attention to detail during placement of the reactor vessel head resulted in additional dose during the evolution.

Within the areas inspected, no violations were identified.

5. **SURVEILLANCE OBSERVATIONS** (61726 and 92902)

During the reporting period, the inspectors ascertained, by direct observation of licensee activities, whether surveillances of safety significant systems and components were being conducted in accordance with technical specifications and other requirements. The inspection included a review of the following procedures and observation of surveillance:

a. During this period, the inspectors reviewed the performance copy of 1-SI-SXP-074-128.B, RESIDUAL HEAT REMOVAL PUMP 1B-B QUARTERLY OPERABILITY TEST, Revision 1. Test data indicated the 1B RHR Pump was operable after receiving a motor changeout during the Unit 1 Cycle 7 outage. However, the inspectors noted PER SQ951758 was written on October 6, 1995, identifying a high vibration condition when the pump was started on miniflow for performance of 1-SI-SFT-074-001.0.

   The inspectors reviewed 1-SI-SFT-074-001.0, RHR INJECTION FLOW RATE MEASUREMENT, PUMP PERFORMANCE AND CHECK VALVE TEST, Revision 5, performed on October 5, 1995, in addition to the actions to correct the vibration conditions noted in PER SQ951758. The licensee determined that the pump feet mounting bolts were loose during testing on October 5. The bolts were tightened and subsequent pump runs indicated that vibrations were acceptable.

   The inspectors concluded the licensee conducted the surveillances as required and corrected the vibration problem in an adequate manner.

b. During this period, the inspectors reviewed the performance copy of SQN-SI-46.5, COMPONENT COOLING SYSTEM PUMP C-S PERFORMANCE TEST, Revision 3. The test was conducted as part of the PMT after refurbishment of the pump as detailed in paragraph 4.a. The test, conducted, on October 8, 1995, demonstrated acceptable operation in accordance with requirements. The Inspectors noted that data for the test demonstrated the pump was operating well. No discrepancies were noted.

Within the areas inspected, no violations were identified.

6. **ONSITE ENGINEERING** (37551 and 92903)

During the reporting period, the inspectors conducted periodic engineering evaluations for regional assessment of the effectiveness of the onsite engineering staff. The inspection included a review of the following activities:

a. During the Unit 1 Cycle 7 outage period, the licensee replaced 84 motor starters with new design starters. The Unit 1 reactor MOV boards were chosen as the highest priority locations for replacement of the new buckets (starters) during this outage. These bucket replacements eliminated the old Arrow-Hart starter designs which had proven unreliable. Engineering provided a new design for bucket replacement, and resolved problems with the vendor to support the outage schedule.

   The inspectors reviewed activities associated with the bucket replacement in the plant and noted that the modification went well. This work resulted in 88 of 199 buckets being replaced during the outage. The other 111 buckets for the Unit 1 reactor MOV boards are scheduled to be replaced during Unit 1 operation prior to the Unit 2 Cycle 7 outage.

On October 27, 1995, the inspectors became aware of a failure of valve 1-FCV-63-152 to operate when given an open signal from the MCR. Plant conditions did not require the valve to be operable. This valve is one with the old Arrow-Hart starters still installed. PER SQ951948 was written addressing this problem and corrective actions were taken in accordance with current standing orders to address the failure of the valve to operate. The inspectors reviewed the PER and determined that appropriate immediate corrective actions were taken.

The inspectors concluded that the new 480V motor starter modification was well designed and easily installed in the plant. However, continuing failures of old Arrow-Hart starters for safety-related valves indicate a need to continue with replacement in a timely manner. In the interim, compensatory measures have been established by the licensee.

b. During this period, the licensee replaced the Unit 1 B TRAIN motor driven AFW pump internals with a new internals package. The inspectors noted the new pump package included stainless steel stationary components. On October 11, 1995, the inspectors met with licensee engineering personnel to discuss the condition of the AFW pumps at Sequoyah. The inspectors were informed that pumps are being closely monitored for degradation in accordance with ASME Section XI requirements. In addition, the inspectors were informed that 2 of the 6 AFW pumps have stainless steel internals, and 3 of the other four pumps have been overhauled since 1988. The inspectors evaluated the licensee's review and implementation of any actions associated with NRC IN 88-87, PUMP WEAR AND FOREIGN OBJECTS IN PLANT PIPING SYSTEMS. The IN discussed wear of AFW pump internals at another plant. The inspectors determined the licensee conducted a good review of the IN and conducted inspections relating to the identified conditions.

The inspectors concluded that engineering and technical support personnel were closely monitoring AFW pump performance and had conducted good reviews of a past industry issue associated with AFW pump degradation.

c. During the last inspection period, the inspectors conducted a review of maintenance/modification activities associated with radiation monitors 2-RE-90-106, UNIT 2 CONTAINMENT BUILDING LOWER COMPARTMENT AIR MONITOR, and 2-RE-90-112, UNIT 2 CONTAINMENT BUILDING UPPER COMPARTMENT RADIATION MONITOR. The review was conducted due to frequent reports from operators of water being observed in the monitor sample lines. The inspectors observed insulation installed on the sample lines near the end of the last period.

During this period, the inspectors continued their review of the licensee's evaluation of the cause of the water in the radiation monitor sample lines. They noted that both Operations and Chemistry personnel indicated that water in the sample lines was reduced after installation of the insulation. However, plant personnel still observed moisture at the monitor filter paper locations. Later in the inspection period, the inspectors noted that the radiation monitors were performing well.

Late in the period, the inspectors met with technical support personnel and discussed the radiation monitor moisture problem. They were informed that during the period, temperatures were taken at several points between containment and the radiation monitors. The engineers determined the insulation on the sample lines helped reduce the moisture problem some. However, the high humidity in containment during summer months causes the moisture problems at the monitors. The cause of recent reduction in moisture in the lines was due to the river temperature water cooling due to cooler local weather. The licensee has proposed a modification to the plant to move the monitors closer to the containment, and to heat trace the lines. However, this modification has lower priority than other issues.

The inspectors concluded that the licensee was focusing both maintenance and technical effort on the radiation monitor sample line moisture problem, but the technical area was not receiving a high priority. The technical issue was understood and a modification to resolve the problem was being considered.

Within the areas inspected, no violations were identified.

7. **PLANT SUPPORT** (64704,71750, 82301 and 92904)

During the reporting period, the inspectors conducted reviews to ensure that selected activities of the following licensee programs are implemented in conformance with the facility policies and procedures and in compliance with regulatory requirements.

Radiological Controls

During the later part of the period, the inspectors reviewed the licensee's ALARA performance for the Unit 1 Cycle 7 outage period. The licensee had established a goal of 250 person-rem for the outage. In addition, a goal of less that 60 personnel contamination events was also established.

Actual person-rem expenditure near the end of the outage was 293. In addition, less than 60 PCEs were projected near the end of the outage.

The inspectors were informed that approximately 33 person-rem resulted from outage scope increase such as additional reactor head work, repair of the bent thermocouple column, and additional steam generator work. In addition, on the day the inspection period ended, the licensee was preparing to work on a RCP seal which exhibited high leakage.

The inspectors concluded the licensee's ALARA performance during the outage was good. However, increased outage scope due to emerging work resulted in increased dose.

Within the areas inspected, no violations were identified.

8. **LICENSEE EVENT REPORT REVIEW** (92700)

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

a. (Closed) LER 327/95-02, Reactor Coolant System (RCS) Leak as a Result of a Fitting not Properly Assembled on the Reactor Vessel Level Indication System (RVLIS). The issue involved licensee identification of a leak on Unit 1 requiring a unit shutdown and partial cooldown to effect repair. A sample program was developed and implemented involving inspection of approximately 450 fittings for disposition prior to unit restart. This event and licensee corrective actions were discussed in inspection report 327, 328/95-06. No additional reviews are required to close this LER.

b. (Closed) LER 327/95-06, Waste Gas Analyzer Setpoint Calibration for Hydrogen Concentrations. The issue involved the WGA being operated incorrectly. The WGA monitors oxygen and hydrogen concentrations to prevent a potential explosive atmosphere in the Waste Gas Decay Tanks. The WGA has three ranges that measure hydrogen concentration. Range 1 has a scale of 0-4 percent, Range 2 has a scale from 0-50 percent, and Range 3 has a scale from 0-100 percent. The hydrogen alarm setpoint, approximately 4% concentration, was calibrated using Range 1, but then was returned to Range 3, since hydrogen levels were usually greater that 50 percent. It was the licensee's practice since October, 1980, to calibrate the hydrogen monitor in Range 1, but to operate in the wider scale of Range 3. It was not until May, 1995, while troubleshooting a problem with the WGA, that the licensee discovered that the setpoint for hydrogen was mechanically set and based on the % span of the chart recorder not the % hydrogen concentration. Thus, with Range 3 selected, the hydrogen setpoint would alarm at approximately 29 percent rather than the approximate 4 percent when Range 1 was used. The alarm logic in

May, 1995, ("and" gate logic) was such that both hydrogen and oxygen (setpoint of less than or equal to 2%) would have to exceed their setpoint for the alarm to activate. It should be noted that prior to 1991, the WGA alarm logic was an "or" gate logic. The change to an "and" gate logic resulted from the corrective actions of LER 327/90-025, Improper Calibration-Oxygen Analyzer Alarm Setpoint of the Waste Gas Disposal System. It appears that when the change was made to the "and" gate logic, there was a lack of comprehensive operating knowledge about the WGA on the part of personnel responsible for the corrective action development and subsequent procedure changes.

The licensee initiated the following corrective action. On May 25, 1995, the LCO for 3.3.3.10 was entered. Chemistry began taking grab samples in accordance with TS 3.3.3.10. The logic to the alarm setpoint was reconfigured in August of 1995, to ensure that the hydrogen input was always energized. Thus, oxygen is the controlling parameter and the oxygen setpoint will be used to alert operators to a potential gas problem. The WGA is scheduled to be replaced in fiscal year 1997 with a new analyzer that is capable of functioning in the required range.

Technical Specification 3.3.3.10, Explosive Gas Monitoring Instrumentation, requires that the alarm setpoints be set to ensure that oxygen is less than or equal to 2 percent whenever hydrogen is greater than 4 percent by volume. Contrary to this requirement, the potential has existed since 1991 for the hydrogen and oxygen to be above their TS limits without actuation of the WGA alarm. This item is identified as NCV 327, 328/95-21-01, Failure to Follow the Requirements of TS 3.3.3.10. This licensee-identified and corrected violation is being treated as a non-cited violation, consistent with Section VII of the NRC Enforcement Policy.

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

9. EXIT INTERVIEW

The inspection scope and results were summarized on October 30, 1995, with those individuals identified 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	Status	Description and Reference
VIO 327, 328/95-08-02	CLOSED	Failure to perform and document prerequisites and NOTES in accordance with procedures, error in drawing 91934-7355A, and failure to provide adequate instructions as

		part of work order 94-01658-00 during performance of the spent fuel pool rerack project. (paragraph 3.i.)
LER 327/95-02	CLOSED	Reactor Coolant System (RCS) Leak as a Result of a Fitting not Properly Assembled on the Reactor Vessel Level Indication System (RVLIS). (paragraph 8.a.)
LER 327/95-06	CLOSED	Waste Gas Analyzer Setpoint Calibration for Hydrogen Concentrations. (paragraph 8.b.)
NCV 327, 328/95-21-01	CLOSED	Failure to Follow the Requirements of TS 3.3.3.10. (paragraph 8.b.)

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

Licensee management was informed of the items closed in paragraphs 3 and 8.

10. ACRONYMS AND ABBREVIATIONS

AFW	-	Auxiliary Feedwater
ALARA	-	As Low As Reasonably Achievable
a.m.	-	Ante Meridiem
AOP	-	Abnormal Operating Procedure
ASME	-	American Society of Mechanical Engineers
ASOS	-	Assistant Shift Operations Supervisor
AUO	-	Assistant Unit Operator
CFR	-	Code of Federal Regulations
CIPT	-	Complex and Infrequently Performed Tests
CS CCS	-	Normal B Train Component Cooling System
EDG	-	Emergency Diesel Generator
EPRI	-	Electric Power Research Institute
ESF	-	Engineered Safety Feature
°F	-	Degrees Fahrenheit
FHI	-	Feedwater Heater
gpm	-	Gallons Per Minute
IN	-	Information Notice
IPE	-	Individual Plant Examination
IR	-	Inspection Report
LCO	-	Limiting Condition for Operation
LER	-	Licensee Event Report
MCR	-	Main Control Room
MOV	-	Motor Operator Valve
MRC	-	Management Review Committee
NCV	-	Non-cited Violation

NRC	-	Nuclear Regulatory Commission
NRR	-	Nuclear Reactor Regulation
ORAM	-	Outage Risk Assessment and Management
PER	-	Problem Evaluation Report
PMT	-	Post Modification Test
PORC	-	Plant Operations Review Committee
PRA	-	Probabilistic Risk Assessment
psi	-	Pounds Per Square Inch
RCP	-	Reactor Coolant Pump
RCS	-	Reactor Coolant System
RHR	-	Residual Heat Removal
RO	-	Reactor Operator
RVLIS	-	Reactor Vessel Level Indication System
RWST	-	Refueling Water Storage Tank
SG	-	Steam Generator
SI	-	Surveillance Instruction
SOS	-	Shift Operator Supervisor
SRO	-	Senior Reactor Operator
SSP	-	Site Standard Practice
TI	-	Technical Instruction
TS	-	Technical Specifications
V	-	Volt
VIO	-	Violation
WGA	-	Waste Gas Analyzer
WO	-	Work Order