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

Report Nos.: 50-327/90-37 and 50-328/90-37

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: November 6, 1990 - December 5, 1990

Lead Inspector: for P. Harmon, Senior Resident Inspector — Date Signed 12/14/90

Inspectors: Scott Shaeffer, Resident Inspector

Approved by: W. S. Little, Chief, Project Section 1, TVA Projects — Date Signed 12/14/90

SUMMARY

Scope:

This announced inspection involved inspection effort by the Resident Inspectors in the area of operational safety verification including control room observations, operations performance, system lineups, radiation protection, safeguards, and conditions adverse to quality. Other areas inspected included surveillance testing observations, maintenance observations, review of previous inspection findings, follow-up of events, review of licensee identified items, and review of inspector follow-up items.

Results:

During this inspection period Unit 2 completed the Cycle 4 refueling outage and began the return to power operations. During the startup process, the licensee experienced problems with reactor coolant pump seals, which required a return to cold shutdown condition on two separate occasions, paragraph 4. Excore nuclear instrument calibration problems continued during the startup of Unit 2, and are described in paragraph 6. While attempting to transfer station power from off-site to on-site supply at 30% power during the startup, a Unit board tripped and resulted in a reactor trip. Actions of the operating crew during this event precipitated the trip and resulted in a violation for failure to follow procedures. The event, trip and violation are described in paragraph 6.

Two violations were identified. Violation 328/90-37-01 involved the Unit 2 entry into operational modes, including initial criticality, with inoperable and miscalibrated nuclear instrumentation, paragraph 6. Violation 328/90-37-02, paragraph 6, involved a failure of Operations personnel to follow the requirements of Administrative Instruction AI-30, Conduct of Operations, during response to a reactor coolant pump trip on Unit 2.

The areas of Operations, Maintenance, and Surveillance were adequate and fully capable to support current plant operations. The observed activities of the control room operators were professional and well executed, but concern for shift crew communications, command and control, and response to upset conditions are expressed in section 6.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

J. Bynum, Vice President, Nuclear Power Production
*J. Wilson, Site Vice President
W. Byrd, Manager, Project Controls/Financial Officer
C. Vondra, Plant Manager
R. Beecken, Maintenance Manager
L. Bryant, Work Control Superintendent
*M. Cooper, Site Licensing Manager
*J. Gates, Technical Support Manager
G. Hipp, Licensing Engineer
*W. Lagergren, Jr., Operations Manager
M. Lorek, Operations Superintendent
*R. Lumpkin, Site Quality Manager
*R. Proffitt, Compliance Licensing Manager
R. Rogers, Technical Support Program Manager
M. Sullivan, Radiological Control Manager
P. Trudel, Project Engineer
R. Thompson, Licensing Engineer
*C. Whittemore, Licensing Engineer

NRC Employees

*W. S. Little, Chief, Project Section 1

*Attended exit interview

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

2. Operational Safety Verification (71707)

a. Control Room Observations

The inspectors conducted discussions with control room operators, verified that proper control room staffing was maintained, verified that access to the control room was properly controlled, and that operator attentiveness was commensurate with the plant configuration and plant activities in progress, and with on-going control room operations. The operators were observed adhering to appropriate, approved procedures, including Emergency Operating Procedures, for the on-going activities. The inspectors observed upper management in the control room on a number of occasions.

The inspector verified that the licensee was operating the plant in a normal plant configuration as required by TS and when abnormal conditions existed, that the operators were complying with the appropriate LCO action statements. The inspector verified that RCS leak rate calculations were performed and that leakage rates were within the TS limits.

The inspectors observed instrumentation and recorder traces for abnormalities and verified the status of selected control room annunciators to ensure that control room operators understood the status of the plant. Panel indications were reviewed for the nuclear instruments, the emergency power sources, the safety parameter display system and the radiation monitors to ensure operability and operation within TS limits.

One violation was identified in the area of control room observations and is discussed in detail in paragraph 6.

b. Control Room Logs

The inspectors observed control room operations and reviewed applicable logs including the shift logs, operating orders, night order book, clearance hold order book, and configuration log to obtain information concerning operating trends and activities. The TACF log was reviewed to verify that the use of jumpers and lifted leads causing equipment to be inoperable was clearly noted and understood. The licensee is actively pursuing correction to conditions requiring TACFs. No issues were identified with these specific logs.

Plant condary chemistry reports were reviewed. The inspector verified that primary plant chemistry was within TS limits.

The implementation of the licensee's sampling program was observed. Plant specific monitoring systems including seismic, meteorological and fire detection indications were reviewed for operability. A review of surveillance records and tagout logs was performed to confirm the operability of the Reactor Protection System (RPS).

No violations or deviations were identified.

c. ECCS System Alignment

The inspectors walked down accessible portions of safety-related systems on Units 1 and 2 to verify operability, flow path, heat sink, water supply, power supply, and proper valve and breaker alignment. The walkdown is in the form of a checklist suggested by the Probabilistic Risk Assessment study conducted for Sequoyah and performed weekly by the inspectors.

The inspectors verified that a selected portion of the containment isolation lineup was correct.

No deviations or violations were identified.

d. Plant Tours

Tours of the diesel generator, auxiliary, control, and turbine buildings, and exterior areas were conducted to observe plant equipment conditions, potential fire hazards, control of ignition sources, fluid leaks, excessive vibrations, missile hazards and plant housekeeping and cleanliness conditions. The plant was observed to be clean and in adequate condition. The inspectors verified that maintenance work orders had been submitted as required and that followup activities and prioritization of work was accomplished by the licensee.

The inspector visually inspected the major components for leakage, proper lubrication, cooling water supply, and any general condition that might prevent fulfilling their functional requirements.

The inspector observed shift turnovers and determined that necessary information concerning the plant systems status was addressed.

No violations or deviations were identified

e. Radiation Protection

The inspectors observed HP practices and verified the implementation of radiation protection controls. On a regular basis, RWPs were reviewed and specific work activities were monitored to ensure the activities were being conducted in accordance with the applicable RWPs. Workers were observed for proper frisking upon exiting contaminated areas and the radiologically controlled area. Selected radiation protection instruments were verified operable and calibration frequencies were reviewed.

No violations or deviations were identified

f. Safeguards Inspection

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 including: protected and vital area access controls; searching of personnel and packages; escorting of visitors; badge issuance and retrieval; and patrols and compensatory posts.

The inspectors observed protected area lighting, and protected and vital areas barrier integrity. The inspectors verified interfaces between the security organization and both operations and maintenance. The Resident Inspectors interviewed individuals with security concerns, visited central or secondary alarm station, and verified protection of safeguards information.

No violations or deviations were identified.

g. Conditions Adverse to Quality

The inspectors reviewed selected items to determine that the licensee's problem identification system as defined in Site Standard Practice SSP-3.2, Problem Reporting, Evaluation, and Corrective Action, was functioning. CAQR's were routinely reviewed for adequacy in addressing a problem or event. Additionally a sample of the following documents were reviewed for adequate handling:

- Work Requests
- Conditions Adverse to Quality, CAQRs
- Radiological Incident Reports
- Problem Evaluation Reports
- Correct-on-the-Spot Documents
- Licensee Event Reports

Of the items reviewed, each was found to have been identified by the licensee with immediate corrective action in place. For those issues that required long term corrective action the licensee was making adequate progress.

No violations or deviations were identified

Adverse trends were identified in the operational safety verification area regarding the lack of command and control rigor and formal communications between shift personnel. Specifics of this concern are detailed in the description of the violation in section 6. General conditions in the plant were adequate. Licensee personnel and management were observed to be very active in housekeeping activities to restore plant material conditions following the refueling outage.

Radiation protection and security are adequate to continue two unit operations.

3. Surveillance Observations and Review (61726)

Licensee activities were directly observed/reviewed to ascertain that surveillance of safety-related systems and components was being conducted in accordance with TS requirements.

The inspectors verified that testing was performed in accordance with adequate procedures; test instrumentation was calibrated; LCOs were met; test results met acceptance criteria and were reviewed by personnel other than the individual directing the test; deficiencies were identified, as appropriate, and any deficiencies identified during the testing were properly reviewed and resolved by management personnel; and system restoration was adequate. For completed tests, the inspector verified that testing frequencies were met and tests were performed by qualified individuals.

The following activities were observed/reviewed with no deficiencies identified except as noted:

a. SI-11, Reactivity Control Systems Moveable Control Assemblies.

The purpose of this SI is to verify operability of the group demand position indicators. The test is performed by placing the full length (shutdown and control) rods on bank select, moving each bank until the appropriate movement has been verified on both the group demand position indicators and the rod position indicators, and returning to the original position to verify all full length rods are operable.

No problems or deviations were identified during the performance of the surveillance. However, various problems with the operability of the intermediate range detectors, which are required to be operable prior to the performance of the SI were identified. These issues are discussed in paragraph 6 of this Inspection Report.

No adverse trends were identified in the area of surveillance performance during this inspection period. The area of surveillance scheduling and management was observed to be adequate and improving.

4. Monthly Maintenance Observations and Review (62703)

Station maintenance activities on safety-related systems and components were observed/reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, industry codes and standards, and in conformance with TS.

The following items were considered during this review: LCOs were met while components or systems were removed from service, redundant components were operable, approvals were obtained prior to initiating the work, activities were accomplished using approved procedures and were inspected as applicable, procedures used were adequate to control the activity, troubleshooting activities were controlled and the repair records accurately reflected the activities, functional testing and/or calibrations were performed prior to returning components or systems to service, QC records were maintained, activities were accomplished by qualified personnel, parts and materials used were properly certified, radiological controls were implemented, QC hold points were established

where required and were observed, fire prevention controls were implemented, outside contractor force activities were controlled in accordance with the approved QA program, and housekeeping was actively pursued.

Work request WP 703-06, RCP Seal Replacement with Cartridge Type Seal, was reviewed. During the Unit 2, Cycle 4 refueling outage the conventional RCP seals were replaced with cartridge type seals on RCP #1 and #2. The modification was performed previously on pumps #3 and 4. The modification involved some cutting and grinding and produced filings and metallic debris in the lower pump seal area. The modification was performed with the pump uncoupled from the motor, and the lower shaft forming a backseat at the top of the thermal barrier against the static head of water in the RCS. This allows seal work while RCS levels are higher than the seal area. Unfortunately, the backseat also becomes a collection point for debris flushed from the seal work area above the backseat. The workplan and pump coupling procedures require seal injection to be initiated prior to lifting the lower shaft for recoupling. Seal injection would then cause any debris collected at the backseat to be flushed into the RCS, preventing the RCS static head from flushing the debris into the seal area.

Communications between Operations personnel and Maintenance personnel during the recoupling process resulted in the seal injection being stopped during the shaft lift and recoupling. As a result, some of the debris from the modification of #1 and #2 RCP entered the seal areas. During the subsequent startup, the #2 RCP seal exhibited symptoms of seal damage and failure. Unit 2 was shut down and the RCS depressurized to allow seal inspection. Seal disassembly was performed and the seal cartridge was replaced. Small amounts of debris were found on the seal face along with a sticky substance resembling tape resin. After replacing the seal the pump was flushed and recoupled. RCP #1 was not inspected at this time, even though the same modification had been performed on its seals. During the restart, #1 RCP exhibited some symptoms of seal damage. After repeated attempts to get the seal to perform correctly, Unit 2 was again shutdown and depressurized for seal repairs. Smaller amounts of grit and debris were found in the #1 RCP seal. This seal was replaced and the plant restarted. All pump seals worked as designed.

The inspector questioned plant management about the decision to not inspect the #1 RCP seal when the first shutdown occurred to examine the #2 pump. Management indicated that even though both #1 and #2 pumps had undergone the same modification, there was no specific evidence that #1 pump was damaged. Furthermore, parts to replace #1 pump seals would not have been available during the #2 pump seal replacement outage. Another consideration in the decision not to inspect #1 pump during the #2 pump shutdown was schedule pressures to return Unit 2 to service. The Outage schedule at the time was already approximately 8 days over the original schedule. Taking an additional two or three days to inspect and repair the #1 pump's seals when no hard evidence of damage had been observed was considered, but decided against by plant management.

No deviations or violations were identified in the area of Maintenance.

5. NRC Inspector Follow-up Items, Unresolved Items, Violations (92701, 92702)

(Closed) URI 327,328/89-12-01, Licensed Power Indication.

The majority of the concerns associated with this issue were resolved in NRC IR 327,328/89-15. The one remaining item concerned the surveillance requirements of TS, Axial Flux Difference (AFD) as stated in TS 2.1. and how they related to thermal power limits of the unit. Since this issue was identified by the inspector in NRC IR 89-12, the requirements for AFD surveillances have been modified due to the incorporation of the AFD monitor as referenced in General Operating Instructions (GOI-5). The AFD monitor now provides the necessary monitoring of AFD limits and operator action is not necessary unless the monitor is declared inoperable. The inspector had no further concerns at this time. This item is closed.

(Closed) VIO 327,328/89-15-03, T.S. 6.8.1 Procedures to Control P[illegible] Within License Limits.

The violation involved the failure of the licensee to establ[illegible] and implement adequate procedures for power operation to maintai[illegible] ermal power within the license limits. The inspector reviewed the r[illegible]ions to General Operating Instruction 5, Normal Power Operation, whic[illegible] were incorporated to establish proper monitoring and control of thermal power. The procedure now requires the unit operator to monitor core thermal power utilizing instantaneous and trend data available from recorders in the control room. Administrative Instruction 6, Log Entries and Review, was also revised to formally record and monitor thermal power to ensure these limits are not exceeded for two consecutive hours or for any 8 hour shift. In addition, the operators are now instructed to take prompt manual action to reduce thermal power to 3411 mw or below upon observing an upward trend in power above 3411 mw. The inspector considers the corrective actions adequate to prevent recurrence of the problem. This item is closed.

6. Event Follow-up (93702)

a. On November 17, 1990, during a post test performance review of the completed portions of Unit 2 startup test procedures following cycle 4 reload, the licensee discovered that the Intermediate Range Monitors (IRMs) were improperly calibrated. A reactor trip would not have been initiated, if required, within the technical specification allowable value of at least 30% of rated thermal power. Between October 31, 1990, and November 17, 1990, there were several manipulations such as rod movements, rod drops, and initial criticality in mode 2 which required the IRMs to be operable. At the time of event discovery, the unit was in Mode 3 with reactor trip breakers open and the IRMs were not required to be operable. The event was reportable in accordance with 10 CFR50.73 as a result of operation prohibited by the TS in that the IRMs were not operable

when the reactor trip breakers were closed and the rods capable of withdrawal.

Workplan 6186 installed the new Gamma-Metrics instrumentation on Unit 2 and incorporated steps to calibrate the Intermediate Range (IR) channels after installation including the cycle-dependent fluence compensation to reflect the Unit 2 core power distribution. During the modification process, however, at the time when each IR channel calibration was completed, the data and procedure needed to calculate the fluence compensation were not available. Consequently, for initial IR channel calibration, Workplans 6186-13 and 6186-14 used vendor supplied data related to a reference neutron source rather than Unit 2 Cycle 5 specific data. The workplan was annotated in the margin that the values used in the calibration were from the vendor rather than the required values from the instruction that performs the necessary calculation. The Workplans, 6186-13 and 6186-14, were closed out October 31, 1990, and both channels were incorrectly declared operable.

On October 31, 1990, the verification of prerequisites began for Surveillance Instruction SI-11, Reactivity Control Systems Moveable Control Assemblies. IR detector operability needed to be established prior to performance of SI-11. A reactor engineer completed procedure 2-PI-NXX-092-001.0, Prestartup NIS Calibration Following Core Load, which calculated a voltage difference that would account for cycle-dependent fluence variations. The IR calibration is performed by calculating a bias term based on the ratio of the sum of selected assembly powers corresponding to the beginning of the upcoming cycle (which is also reduced by 20% for conservatism) and the last IR calibration check (0-SI-NXX-092-079.0) of the previous cycle. This bias term is used to calculate the expected full power voltage for the upcoming cycle. The voltage difference between the expected full power voltage and the assumed full power voltage is then used to calibrate the IR channels. The Unit 2 bias term also included a conservatism based on a comparison to Unit 1 data. The Unit 1 core closely models the Unit 2 core design and therefore provided the best available data for the voltage difference calculations for adjusting the Gamma-Metrics channels. This voltage difference was to be inserted in instrument calibration procedures 2-PI-ICC-092-N35.1, Gamma-Metrics Channel I Full Power Alignment, and 2-PI-ICC-092-N36.2, Gamma-Metrics Channel II Full Power Alignment, which align the Gamma-Metrics channels to actual reactor power. On October 31, 1990, the reactor engineer completed his procedure and carried the appropriate data page to a senior instrument mechanic involved with NIS activities. The reactor engineer assumed the workman knew what was to be done with the data. However, the instrument mechanic did not understand all the procedures required to adjust the IRMs for startup and did not bring to the attention of his supervision that he had information from Reactor Engineering related to IRM calibrations. The following day Reactor Engineering delivered a page from the prestartup calibration procedure to an instrument maintenance (IM)

General Foreman indicating which PIs had to be performed. This information was not acted upon and the IM general foremen did not remember receiving the information. SI-11 was subsequently started on November 1, 1990, and completed on November 2, 1990. In addition, SI-11 was reperformed on November 11, 1990, as well as SI-43, Rod Drop Time Measurement. During the performance of SI-11 and SI-43, the IRMs are required to be operable as a result of the reactor trip breakers being closed and rods capable of withdrawal.

The Restart Test Program is described by RTI-1, Restart Sequence. This instruction establishes the restart testing program and includes a tabulation of the major phases of the restart test program, a tabulated summary of the Restart Test Sequence indicating applicable plant instructions to be performed, and acceptance and review criteria for each instruction. The licensee began preparations for startup testing on November 10, 1990. The purpose of the Restart Test Program conducted in Mode 2 is to determine if the operating characteristics of the core are consistent with the design predictions and to ensure that the core can be operated as designed. This is accomplished by comparing the measured value of selected key core parameters with their predicted design values and by obtaining data required for proper recalibration of core surveillance and protection instrumentation.

Documentation indicating that preliminary evaluations of test results have been performed on each test prior to proceeding to the next testing phase are included in RTI-1.

Step 1 of Phase A of RTI-1, includes verification of IR adjustment by instrument maintenance to include values from 2-PI-NXX-092-001.0. This verification should ensure that the reactor would not be taken critical until both IR channel calibrations were complete. The sign off for this step was not completed before Phase 'B' was started due to oversight by the assigned test directors.

On November 11, 1990, at approximately 0945, Phase 'B' testing began with rod drop time measurement (SI-43). SI-43 prerequisites required source range instrumentation to be in operation. However, the procedure does not require Operations to verify operability of the IRMs. It is assumed by Operations that operability exists if all associated SIs are complete and within frequency and there are no outstanding work requests or workplans on the equipment. Earlier on November 11, 1990, a prejob test briefing was conducted with the dayshift restart test group. During the meeting, the Test Director believed that the activities associated with Phase 'A' testing were complete and that the nightshift Test Director had performed the prestartup NIS calibration procedure approximately 10 days earlier. RTI-1 testing Phase 'A' was not signed off by the nightshift Test Director. The dayshift Test Director, however, signed the remaining blanks, excluding the IRM/PRM calibration step intending for the

nightshift Test Director to complete the signoffs, since he had been directly involved in the step.

Rod drop testing was complete at approximately 1400 on November 11, 1990, and RTI-3.1, Initial Criticality, commenced at approximately 1945 on November 11, 1990, when the unit entered Administrative Mode 2. At this time, the control rods were withdrawn and the dilution to criticality began. Unit 2 reactor was taken critical at 1730 EST on November 12, 1990. Zero power physics testing was started and data were obtained at the point of adding nuclear heat (POAH). The reactor was taken subcritical at approximately 0450 EST on November 13, 1990, in preparation for reentry into Mode 5 for reactor coolant pump seal maintenance.

A reactor engineer was reviewing the criticality data on the midnight shift of November 16, 1990, when he noted that the IR channel outputs at the POAH were similar to the values previously exhibited at the POAH by the nonconservatively adjusted Unit 1 IR channels. A record search was initiated on November 17, 1990, to verify that procedures 2-PI-ICC-092-N35.1 and 2-PI-ICC-092-N36.2 had been performed. No records were found. A work request was then completed to measure the "as found" voltage on one Unit 2 IR channel. The measured voltage confirmed that the calibrations to implement the calculated voltage difference had not been conducted. Subsequent analysis of data concluded that Unit 2 had entered Mode 2 with inoperable IR channels. Upon discovery, instrument maintenance was supplied the proper calibration data and the Intermediate Range Monitors (IRMs) voltage adjustments were completed as required.

This event involved the Nuclear Instrumentation System Reactor Trips, and included the Source Range (SRM) high neutron flux trip block function (P-6), the Intermediate Range (IRM) high neutron flux trip, and the Power Range Monitor (PRM) high neutron flux trip low setpoint.

During this event, the SRMs were operable and would have initiated a reactor trip at approximately 1 x 10 E + 5 counts per second until blocked at the P-6 permissive. At this point, the IRMs should initiate a reactor trip at approximately 20 percent rated thermal power (conservatively) until blocked at the P-10 permissive at approximately 10 percent power. At the same time, the PRMs would have initiated a reactor trip at the low power trip setpoint of approximately 20 percent rated thermal power (conservatively) below the P-10 permissive. Above the P-10 permissive, only the high power trip setpoint is active (conservatively set at 50 percent RTP).

Prior to entry into Mode 2, the PRM high neutron flux low setting was adjusted to 20 percent and the high setting was adjusted to 50 percent. The IRM high neutron flux trip was adjusted to 20 percent also. Including the 10 percent conservatism in the PRM low setting, the trip setpoint would have been 30 percent (worst case) which is

less than the 35 percent trip assumed in the UFSAR. The plant safety analysis takes no credit for the IR trips which would have tripped at approximately five times their required setpoint. Above 10 percent power, the PRM low flux trip and IRM trips are blocked (P-10) leaving the PRM high flux trip for reactor protection. The reactor was maintained at less than 1 percent power during the event and permissive P-10 was never reached due to the reactor shutdown for reactor coolant pump seal repair.

The miscalibration and subsequent inoperability of the intermediate range monitors while entering Mode 2 operations is a violation of TS 3.3.1 and is identified as VIO 328/90-37-01, Inoperable Intermediate Range Monitors During Startup. Although the IRM trip setpoints were outside the Technical Specification limits, the licensee established that the consequences were bounded by the UFSAR accident analysis. Additionally, the PRMs trip setpoints were adjusted conservatively during the event, with high flux at 50 percent Rated Thermal Power (RTP) and low flux at 20 percent RTP.

This event raised a number of concerns. Communications between management and workers broke down when the voltage adjustments supplied by Reactor Engineering to Instrument Maintenance were not understood and he did not ask for help. It was not clear to the Instrument Mechanic what was to be done with the calibration data and his supervision was not involved in the process. There was a follow-up by Reactor Engineering, however, verification of the completed IRM calibration process was still not accomplished. Inadequate measures were taken in the close-out of work plan 6186 in assuring that additional adjustments were positively accomplished to declare the IRMs operable. Additionally, a lack of management follow-up, to assure conformance in the startup process as defined in RTI-1, was apparent whereby phase 'B' of the testing sequence was begun before phae 'A' was verified as complete. These actions appear to be a combination of procedure inadequacy, improper personnel follow-up of work performed, a lack of management oversight at various levels, and poor communication.

Two additional events since June of 1990 have also occurred involving the potential for or actual miscalibration of nuclear instrumentation. The first occurred during the Unit 1 startup in June of 1990 when Unit 1 was operated in violation of TS because of nonconservative power and intermediate range NIS calibrations. During the event, the Power Range (PR) channels had been initially calibrated with nonconservative values prior to Unit 1 startup from the refueling outage because of a misinterpreted equation used to calculate preliminary detector current values. This error caused the PR channels to indicate lower than actual power by 24 to 31 percent of the power level, and resulted in the NIS trip setpoints being set 24 to 31 percent higher than their TS required values during startup evolutions. Subsequent evaluation also determined that errors had been made in predicting the prestartup IR detector voltage resulting

in the IR detectors indicating approximately one-half decade below actual reactor power. The preliminary PR calibration values were incorrectly calculated based on misinterpreted vendor information. The Westinghouse guidance stated that, "The expected values of these currents can be estimated from the last previous cycle's incore-excore calibration and the predicted X-Y power distribution for the L3P cycle (low leakage core) at hot full power conditions". The licensee's reactor engineering group interpreted this to mean the NIS currents from the last end of life incore-excore calibration performed in the previous cycle, in combination with the beginning of life power distributions from both cycles. The preliminary IR calibration was based on a factory preset voltage rather that previous cycle data due to the new Gamma-Metrics detectors, plus an additional conservatism to the factory recommendation. The factory preset value was adjusted to be more conservative using beginning of life power distribution predictions for the current and previous cycle. These measures, however, were shown not to be sufficiently conservative.

A second event was discovered on November 29, 1990, which involved a potential for a miscalibration of power range channels N41 through N44. During the performance of the incore/excore detector single point alignment for the power range channels, an error was made in transferring data from the most recent performance of 2-PI-NXX-092-001.0, Prestartup NIS Calibration Following Core Load. Step 6.1(1)B requires the recording of slopes of top and bottom detector plots. The bottom detector slope should have been recorded as a negative value for each channel. However, during the transfer process the negative sign was dropped. The error was also not identified by the independent verification process. The error was identified during the calibration of the power range channels by instrument technicians when the erroneous value was attempted to be utilized in the instrument. However, due to the quantity of the error, the value could not be physically used as valid input. This potential miscalibration did not result in any equipment being declared inoperable. The corrected values were provided to instrument maintenance for proper calibration of the power range detectors.

Each of the three core monitoring events described above appear to have resulted from a number of different problems, ie. procedural errors, reactor engineering and instrument maintenance interfaces, lack of management oversight in procedure completion and sign-off, personnel error, and a degree of uncertainty in the operation of the newly incorporated Gamma-Metrics detectors. Each of the events, however, involved interaction with Reactor Engineering, both in the discovery of the events and in the various causes and lack of early identification. NRC Inspection Report 327,328/90-29 expressed a concern regarding the staffing and experience of the Reactor Engineering unit and the ability of the group to provide the necessary review and interpretation of core monitoring, nuclear

instrument calibrations, and special nuclear material storage. These concerns are of even greater importance to the inspector due to the two more recent events involving potential and actual miscalibration of nuclear instrumentation channels at Sequoyah. The status of the Reactor Engineering group's experience and current staffing levels should continue to receive management assessment of the ongoing changes and their effect on the safe operation of the facility.

b. On November 23, 1990, at 4:29 a.m., Unit 2 tripped from approximately 10% power. The trip signal was from Pressurizer Low Pressure signal from the Reactor Protection System. The low pressure was the result of a power reduction that was not properly coordinated by the operating crew. Reactor power was reduced at a faster rate than turbine power in response to a reactor coolant pump trip while at 30% power. The inspector interviewed control room personnel and reviewed logs to obtain the following information.

On November 23, 1990, at 4:23 a.m., operators were in the process of transferring the Unit 2, 6.9 KV Unit boards from the alternate source (Start Bus) to the normal source (Unit Station Transformer) using GOI 2, Plant Startup from Hot Standby to Minimum Load. After transferring the Unit boards to the normal feeder source, the Balance of Plant Operator (BOP) returned the transfer selector switches for each Unit board to the AUTO position, which would allow the alternate source to re-energize the Unit boards if the normal feeder is lost. When the BOP operator returned the transfer switch for the 2D Unit board to the AUTO position, the normal feeder to the board unexpectedly tripped, but the alternate feeder did not close in as designed. As a result, the 2D Unit board was deenergized, tripping the #2 Reactor Coolant Pump. Since reactor power was less than 35%, the P-8 permissive was in effect. P-8 allows a single RCP trip without a direct reactor trip below 35% power.

The LRO began reducing reactor power after asking the SOS if he (the LRO) should begin shutting down. The SOS answered "Yes". At that time the LRO began driving control rods in to reduce reactor power, but did not monitor important parameters such as RCS temperature and pressure. The applicable procedure, AOI-5, Unscheduled Removal of an RCP Below P-8, does not require immediate or expeditious power reduction, but instead stipulates that the reactor is to be shut down to Hot Standby, Mode 3, within 1 hour.

Immediately after the pump trip, the BOP began taking manual control of steam generator levels, an immediate action specified in AOI-5. The ASOS began a turbine load decrease of approximately 3% per minute. The SOS assumed the duties of procedure reader when the ASOS took control of the turbine. This action by the SOS is in direct conflict with AI-30, Conduct of Operations, subsection 8.3.1, Procedure Reader Selection. This subsection is part of section 8.3, Response to Events. Section 8.3 contains the requirements of crew duties and conduct during abnormal events and is the guidance for

crew training for responding to events. Section 8.3.1 specifies that the SOS shall select an individual to perform the role of Procedure Reader in a specific priority, with the unit ASOS as the first priority selection. At the end of the priority list for selecting a procedure reader is a paragraph that states "In no case is the SOS to fill the role of procedure reader during actual plant emergencies." This prohibition ensures that the SOS is free to provide overview control of the event, and is reinforced during training. As a direct result of the SOS not taking command of the event and directing the ASOS and the LRO, reduction of reactor power and turbine power were not coordinated. This lack of coordination resulted in a power mismatch, with reactor power reduced faster than turbine power. With this mismatch, temperature in the RCS dropped rapidly, causing a pressurizer level reduction and a resulting low pressure trip.

Loss of a reactor coolant pump below P-8 should not result in a reactor trip if the operating crew takes proper action. The event was characterized by a lack of command and control by the SOS and the ASOS, lack of familiarity by the LRO of the immediate actions of AOI-5, and ineffective and informal communication by the operating crew. Weaknesses in these areas were noted in the recent operator requalification exams administered by the NRC in September of 1990.

The cause of the trip of the normal feeder to the 2D Unit Board and the failure of the automatic transfer of the alternate feeder is still under investigation. Several attempts to recreate the trip and transfer sequence were made with no repeats of the events.

After the trip, the plant stabilized with all controls and safety features functioning as designed.

AI-30, Conduct of Operations, section 8.3, Response to Events, states that the operator should await the SOS concurrence and then initiate corrective action as directed if the event is not clear or is slowly developing. Section 17, Communications, specifies that verbatim repeat-back of all operational communications is required by all onshift personnel at all times. The requirements of AI-30 were not followed in several important aspects during this event, as listed below:

- Command of the event was not taken by the SOS, who became involved in the procedure reading process, which is specifically prohibited by AI-30.

- The ASOS did not assume his duties as procedure reader as required by training and procedure, but instead became involved with turbine load reduction.

- The LRO was not directed by the SOS to begin a power reduction at some specified rate.

- The ASOS and LRO took independent action, and did not communicate effectively to each other or to the SOS what they were doing and at what rate.

- The LRO did not carefully monitor vital parameters such as RCS temperature and pressure during the power reduction, and subsequently did not anticipate and prevent the reactor trip.

- Communications between crew members was ineffective and informal. The requirement to communicate clearly and to repeat-back orders and directives was not followed.

Failure to follow the requirements of AI-30 in several important aspects is a violation, and will be tracked as VIO 328/90-37-02.

7. Exit Interview (30703)

The inspection scope and findings were summarized on December 5, 1990, with those persons indicated in paragraph 1. The Senior Resident Inspector described the areas inspected and discussed in detail the inspection findings listed below. The licensee acknowledged the inspection findings and did not identify as proprietary any of the material reviewed by the inspectors during the inspection.

Inspection Findings:

Two violations were identified.

VIO 328/90-37-01, Entry into Mode 2 with Intermediate Range Detectors Inoperable.

VIO 328/90-37-02, Failure to Follow the Requirements of AI-30, Conduct of Operations, Results in a Reactor Trip.

During the reporting period, frequent discussions were held with the Site Director, Plant Manager and other managers concerning inspection findings.

8. List of Acronyms and Initialisms

ABGTS- Auxiliary Building Gas Treatment System
ABI - Auxiliary Building Isolation
ABSCE- Auxiliary Building Secondary Containment Enclosure
AFD - Axial Flux Difference
AFW - Auxiliary Feedwater
AI - Administrative Instruction
AOI - Abnormal Operating Instruction
AUO - Auxiliary Unit Operator
ASOS - Assistant Shift Operating Supervisor
ASTM - American Society of Testing and Materials

BIT - Boron Injection Tank
BFN - Browns Ferry Nuclear Plant
BOP - Balance of Plant Operator
C&A - Control and Auxiliary Buildings
CAQR - Conditions Adverse to Quality Report
CCS - Component Cooling Water System
CCP - Centrifugal Charging Pump
CCTS - Corporate Commitment Tracking System
CFR - Code of Federal Regulations
COPS - Cold Overpressure Protection System
CS - Containment Spray
CSSC - Critical Structures, Systems and Components
CVCS - Chemical and Volume Control System
CVI - Containment Ventilation Isolation
DC - Direct Current
DCN - Design Change Notice
DG - Diesel Generator
DNE - Division of Nuclear Engineering
ECN - Engineering Change Notice
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EI - Emergency Instructions
ENS - Emergency Notification System
EOP - Emergency Operating Procedure
EO - Emergency Operating Instruction
ERCW - Essential Raw Cooling Water
ESF - Engineered Safety Feature
FCV - Flow Control Valve
FSAR - Final Safety Analysis Report
GDC - General Design Criteria
GOI - General Operating Instruction
GL - Generic Letter
HVAC - Heating Ventilation and Air Conditioning
HIC - Hand-operated Indicating Controller
HO - Hold Order
HP - Health Physics
ICF - Instruction Change Form
IDI - Independent Design Inspection
IN - NRC Information Notice
IFI - Inspector Followup Item
IM - Instrument Maintenance
IMI - Instrument Maintenance Instruction
IR - Inspection Report
IR - Intermediate Range
IRM - Intermediate Range Monitors
KVA - Kilovolt-Amp
KW - Kilowatt
KV - Kilovolt
LER - Licensee Event Report
LCO - Limiting Condition for Operation
LRO - Lead Reactor Operator

LIV - Licensee Identified Violation
LOCA - Loss of Coolant Accident
MCR - Main Control Room
MI - Maintenance Instruction
MR - Maintenance Report
MSIV - Main Steam Isolation Valve
NB - NRC Bulletin
NIS - Nuclear Instrumentation System
NOV - Notice of Violation
NQAM - Nuclear Quality Assurance Manual
NRC - Nuclear Regulatory Commission
OSLA - Operations Section Letter - Administrative
OSLT - Operations Section Letter - Training
OSP - Office of Special Projects
PLS Precautions, Limitations, and Setpoints
PM - Preventive Maintenance
PPM - Parts Per Million
PMT - Post Modification Test
PORC - Plant Operations Review Committee
PORS - Plant Operation Review Staff
PRMA - Power Range Monitors
PRA - Probabalistc Risk Assessment
PR - Power Range
PRD - Problem Reporting Document
PRO - Potentially Reportable Occurrence
QA - Quality Assurance
QC - Quality Control
RCA - Radiation Control Area
RCDT - Reactor Coolant Drain Tank
RCP - Reactor Coolant Pump
RCS - Reactor Coolant System
RG - Regulatory Guide
RHR - Residual Heat Removal
RM - Radiation Monitor
RO - Reactor Operator
RPI - Rod Position Indication
RPM - Revolutions Per Minute
RPS - Reactor Protection System
RTI - Restart Test Instruction
RTP - Rated Thermal Power
RTD - Resistivity Temperature Device Detector
RWP - Radiation Work Permit
RWST - Refueling Water Storage Tank
SER - Safety Evaluation Report
SG - Steam Generator
SI - Surveillance Instruction
SMI - Special Maintenance Instruction
SOI - System Operating Instructions
SOS - Shift Operating Supervisor
SQM - Sequoyah Standard Practice Maintenance
SQRT - Seismic Qualification Review Team

SR - Surveillance Requirements
SRO - Senior Reactor Operator
SRM - Source Range Monitor
SSOMI - Safety Systems Outage Modification Inspection
SSQE - Safety System Quality Evaluation
SSP - Site Standard Practice
SSPS - Solid State Protection System
STA - Shift Technical Advisor
STI - Special Test Instruction
TACF - Temporary Alteration Control Form
TAVE - Average Reactor Coolant Temperature
TDAFW - Turbine Driven Auxiliary Feedwater
TI - Technical Instruction
TREF - Reference Temperature
TROI - Tracking Open Items
TS - Technical Specifications
TVA - Tennessee Valley Authority
UHI - Upper Head Injection
UO - Unit Operator
URI - Unresolved Item
USQD - Unreviewed Safety Question Determination
VAC - Volts Alternating Current
VDC - Volts Direct Current
VIO - Violation
UFSAR - Updated Final Safety Analysis Report
WCG - Work Control Group
WP - Work Plan
WR - Work Request