UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30303

Report Nos.: 50-259/83-60, 50-260/83-60, and 50-296/83-60

Licensee: Tennessee Valley Authority
500A Chestnut Street
Chattanooga, TN 37401

Docket Nos.: 50-259, 50-260 and 50-296

License Nos.: DPR-33, DPR-52, and DPR-68

Facility Name: Browns Ferry 1, 2, and 3

Inspection at Browns Ferry site near Decatur, Alabama

Inspector: Ross C. Butcher for — 3/12/84
G. L. Paulk — Date Signed

Approved by: Ross C. Butcher for — 3/13/84
F. S. Cantrell, Section Chief — Date Signed
Division of Project and Resident Programs

SUMMARY

Inspection on December 26, 1983 - January 25, 1984

Areas Inspected

This routine inspection involved 120 resident inspector-hours on site in the areas of operational safety, surveillance, management controls, maintenance, physical protection, TMI item, reactor trips, drywell to torus pressure control, reportable occurrences, and lubrication oil control.

Results

Five violations were identified. Two violations were identified in operational safety and three violations were identified in the drywell to torus pressure control section. (One of these violations had two examples.)

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   G. T. Jones, Power Plant Superintendent
   J. E. Swindell, Assistant Power Plant Superintendent
   J. R. Pittman, Assistant Power Plant Superintendent
   L. W. Jones, Quality Assurance Supervisor
   W. C. Thomison, Engineering Section Supervisor
   A. L. Clement, Chemical Unit Supervisor
   D. C. Mims, Engineering and Test Unit Supervisor
   A. L. Burnette, Operations Supervisor
   Ray Hunkapillar, Operations Section Supervisor
   T. L. Chinn, Plant Compliance Supervisor
   C. G. Wages, Mechanical Maintenance Section Supervisor
   T. D. Cosby, Electrical Maintenance Section Supervisor
   R. E. Burns, Instrument Maintenance Section Supervisor
   J. H. Miller, Field Services Supervisor
   A. W. Sorrell, Supervisor, Radiation Control Unit BFN
   R. E. Jackson, Chief Public Safety
   R. Cole, QA Site Representative Office of Power

   Other licensee employees contacted included reactor operators and senior reactor operators, auxiliary operators, craftsmen, technicians, public safety officers, and engineering personnel.

2. Management Interviews

   Management interviews were conducted on January 13 and 27, 1984, with the Power Plant Superintendent and/or Assistant Power Plant Superintendents and other members of his staff. The licensee was informed of the five violations identified during this report period. The licensee has taken positive action to ensure regulatory requirements are being met. A brief description of this program is included in paragraph 7.

   Media interest this month has been involved with licensed operator requalification exams, work force layoffs to meet regulatory requirements, Browns Ferry improvement plan, and TVA tugboat sinking near the site.

3. Licensee Action on Previous Inspection Findings

   a. (Closed) Unresolved (259/83-27-09) Incorrect use of MIN fuses in plant installations. The licensee took corrective action to verify compliance and configuration control of electrical circuit fuse installation. This item is considered closed.

b. (Closed) Open Item (259/83-27-02) Loose conduit supports on EECW pressure switches 67-54 and 67-55. The licensee took action to correct the loose conduits. This item is closed.

c. (Closed) Open Item (259/83-27-04) Electrical Maintenance Instruction (EMI) 4 related to battery analysis was unclear as written. The licensee revised EMI 4 to clarify the vague steps in the procedure. This item is considered closed.

d. (Closed) Violation (296/83-27-03) Installation of portable test gages on the residual heat removal system without traceability. The test pressure gages were removed. The instrument mechanic section was informed during a safety meeting of the importance of following procedures. This item is closed.

e. (Closed) Violation (260/83-27-08) Electrical fuses in Backup Control Panel 25-32 were incorrectly installed. The fuses were changed out. A survey of safety-related control panels was made and approximately 75 fuses were found to be the wrong fuse or incorrectly installed. Fuse training was held with responsible personnel. This item is considered closed.

4. Unresolved Items

There was one new unresolved item identified in section 14.

5. Operational Safety

The inspectors were kept informed on a daily basis of the overall plant status and any significant safety matters related to plant operations. Daily discussions were held each morning with plant management and various members of the plant operating staff.

The inspectors made frequent visits to the control rooms such that each was visited at least daily when an inspector was on site. Observations included instrument readings, setpoints and recordings; status of operating systems; status and alignments of emergency standby systems; purpose of temporary tags on equipment controls and switches; annunciator alarms; adherence to procedures; adherence to limiting conditions for operations; temporary alterations in effect; daily journals and data sheet entries; and control room manning. This inspection activity also included numerous informal discussions with operators and their supervisors.

General plant tours were conducted on at least a weekly basis. Portions of the turbine building, each reactor building and outside areas were visited. Observations included valve positions and system alignment; snubber and hanger conditions; instrument readings; housekeeping; radiation area controls; tag controls on equipment; work activities in progress; vital area controls; personnel badging, personnel search and escort; and vehicle search and escort. Informal discussions were held with selected plant personnel in their functional areas during these tours. In addition, a complete (accessible areas) walkdown which included valve alignment, instrument alignment, and switch positions was performed on the core spray system, high pressure coolant injection system, standby liquid control system, direct-current battery systems (station and diesel generator), the containment atmosphere dilution system, the drywell to torus differential pressure system, and the fuel pool cooling system. The inspections this report period have been exhaustive and comprehensive in an effort to assure regulatory requirements have been met. Many plant supervisors and managers accompanied the inspector on plant tours during this inspection interval. The inspection effort has identified numerous plant deficiencies. A sampling of these deficiencies is noted below: (These samples refer to Units 1 and 2.) (a) containment atmospheric dilution valves 84-8A/D supports missing; (b) air solenoid valves to both reactor building to torus vacuum breakers not bolted down; (c) torus isolation valve for level transmitter 64-159B missing a body-to-bonnet retaining nut; (d) conduit for core spray pump motor leads '1B' not supported; (e) residual heat removal pump 'B' and 'D' area not adequately cleaned; (f) Power leads to core spray motor operated valve 75-30 conduit support brackets missing; (g) condensate transfer piping Unit 1 reactor building (southend, elevation 565 ft.), cable support broken; (h) various valve packing gland retainers/lock nuts not installed or secured. Examples: 0-85-502, 1-77-661, vent valve for pressure indicator 85-2, instrument valves for level transmitters 64-159B, 64-159A; (i) several resistance temperature detector connecting wires pulled from conduit cables for torus temperature monitoring; (j) several electrical conduits on High Pressure Coolant Injection (HPCI) system not mounted to support brackets; (k) Unit 2 Reactor Core Isolation Cooling (RCIC) steam supply line trap had damaged conduits due to overheating; (l) Residual Heat Removal (RHR) pump 2D instrument line not mounted.

The licensee has taken immediate corrective action to repair the above concerns. The licensee was informed that the above concerns are a violation to 10 CFR 50, Appendix B, Criterion X. (259/260/83-60-01). Further details are included in paragraph 7.

On December 31, 1983, the on-duty chemistry analyst observed that Unit 1 reactor water sample taken at 3:20 a.m., had a chloride concentration of 525 ppb. Steam flow was greater than 100,000 Lbm/hr., however, the analyst was not aware of the current steaming rate. Although the chloride maximum limit for greater than 100,000 Lbm/hr. is .5 ppm, the analyst did not adequately inform the unit shift engineer until 11:05 a.m. The shift engineer took appropriate action after he was made aware of the out of specification reading. An orderly shutdown was initiated at 12:20 p.m., December 31, 1983, due to water quality out of specification and possible resin intrusion. An orderly shutdown was terminated at 2:35 p.m., after chloride concentration was confirmed to be within specification and the suspected source isolated. No action to shutdown the unit was taken from 3:20 a.m. to 11:05 a.m. as required by Technical Specification 3.6.B.3. The Plant Superintendent was informed of the violation at the exit on January 13, 1984. (259/84-03-02).

On January 20, 1984, during the performance of Surveillance Instruction 4.1.A-7 (Reactor Water Level Functional Test and Calibration) on Unit 1, the sensing line to LIS-3-208-C (RCIC/HPCI hi water level trip) low side blew out. In order to stop the leak from the blown sensing line LIS-3-203D was isolated at the top of the panel until repairs were made. The blow-out was due to a Swagelok fitting not being properly fitted to the sensing line. The connection was repaired and the system returned to normal operability.

On December 29, 1983, Unit 1 went critical after an eight month refueling outage. This included weld overlay repair of piping cracks caused by intergranular stress corrosion cracking, torus modifications, and turbine repairs.

On January 1, 1984, a partially submerged TVA tugboat moored east of the plant intake structure was identified to be leaking fuel oil by the Alabama Marine Patrol. The fuel oil vents were plugged to prevent the release of fuel to the river. The effects to waterfowl were minimal and there was no operational hazard to the plant.

On January 7, 1984, while attempting to reduce power due to turbine vibration, the Unit 1 reactor was manually tripped due to control rods being moved out-of-sequence. This resulted in a special Inspection Report 84-02.

On January 14, 1984, the off-gas building flooded due to the rupture of a 4-inch raw cooling water line. The line break occurred due to pipe settling.

On January 21, 1984, Unit 2 scrammed after continuous operation since December 22, 1983. This occurred during performance of main steam line high radiation isolation surveillance.

During this report period, Unit 3 remained in a refueling outage. On January 23, 1984, outage work was curtailed as noted in Section 7.

6. Surveillance Testing Observation

This inspectors observed and/or reviewed the below listed surveillance procedures. This inspection consisted of a review of the procedure for technical adequacy, conformance to Technical Specifications, verification of test instrument calibration, observation on the conduct of the test, removal from service and return to service of the system and a review of test data.

a.	S.I. 4.7.A.4.a	Vacuum Breaker Cycle Test
b.	S.I. 4.6.B.3	Coolant Chemistry Analysis
c.	S.I. 2	Operator Daily Logs
d.	S.I. 4.2.F-17	Drywell to Suppression Chamber Differential Pressure
e.	RTI 4	Full Core Shutdown Margin Test

No violations or deviations were noted in this area.

7. Management Controls and Regulatory Compliance

The events at Browns Ferry during the past year have caused the licensee management to reevaluate their position relative to management controls necessary to assure regulatory compliance. The number of regulatory violations during 1983, has exceeded the number of violations identified in the preceding eighteen month SALP period. Thus, violations have increased rather than decreased as the licensee had expected. The licensee reviewed the latest NRC reports, INPO Audit Reports, licensee event reports, and the latest SALP report, and came to the conclusion that positive action must be taken to meet regulatory requirements.

Immediate steps that have been taken to assure regulatory compliance is maintained have included: curtailment of Unit 3 outage operations, resulting in the temporary layoff of 449 workers; reevaluation of management control methods and effectiveness; and the development of an improvement plan. The proposed improvement plan is outlined as follows:

a. SHORT-TERM IMPROVEMENTS:

(1) Increase management awareness of their responsibility, authority, and accountability for strict adherence to regulatory requirements.

(2) Increase time available for plant supervisors to be involved in workplace activities.

(3) Increase employee awareness of their responsibility and accountability for strict adherence to regulatory requirements.

(4) Reorganize the plant to achieve better management control of plant activities.

(5) Reassign/retrain personnel based on performance evaluations.

(6) Assign division program manager representative onsite to provide independent management review of program implementation in the specified areas.

(7) Upgrade licensed operator training and requalification training.

(8) Evaluation of regulatory compliance history.

b. LONG-TERM IMPROVEMENTS:

(1) Resolve open deficiencies.

(2) Ensure that the backlog of modification paperwork is brought up to date and closed out.

(3) Ensure division and plant procedures are clear, concise, correct, and complete.

(4) Improve interaction between the Division of Engineering Design (EN DES) and the plant staff.

(5) Increase direct involvement of OQA in field activities.

(6) Streamline the procurement process.

(7) Establish an onsite training organization under the supervision of the Training Branch with responsibility for all onsite training activities. Work toward INPO accreditation of BFN training programs.

(8) Control future plant modifications.

NRC Violations in 1983 can be categorized to reflect the following deficiencies:

(1) Failure to follow procedures, both when the procedure is adequate, as well as, when the procedure is unclear. Frequently, personnel performing required procedures do not question the adequacy of the procedures, although in some cases, it is obvious the procedure will not work.

(2) Failure of plant staff to properly inform their supervisors or managers of known problems.

(3) Failure to perform work correctly and completely, many times failing to return systems to the as-configured condition.

(4) Evaluations of various known problem areas or special events are shallow in scope and inconclusive in results.

(5) Quality control and engineering is not actively involved in field activities and modification control at the work site.

These basic areas reflect a general weakness of management control functions at all levels from foreman to top managers (at the site and in support organizations).

The inspector will monitor the proposed improvement plan objectives and results to ascertain that regulatory requirements are being satisfied.

8. Maintenance Observation

During the report period, the inspectors observed the below listed maintenance activities for procedure adequacy, adherence to procedure, proper tagouts, adherence to Technical Specifications, radiological controls, and adherence to quality control hold points.

a. Activities associated with Unit 1 and 2 safety equipment repairs as noted during inspector and licensee representative plant tours.

b. Unit 3 outage work until outage work was curtailed.

c. Nylon bolt replacements on diesel generator 'A' 125 volt distribution panel in accordance with NEB 831130218.

d. Unit 3 I.S.I. weld inspection for cracks in accordance with I.E. Bulletin 83-02 has been completed. All welds were satisfactory except one which was rejected.

There were no violations or deviations in the above area.

9. Plant Physical Protection

During the course of routine inspection activities, the inspectors made observations of certain plant physical protection activities. These included personnel badging, personnel search and escort, vehicle search and escort, communications and vital area access control.

No violations or deviations were identified within the areas inspected.

10. TMI Item I.A.1.3 of NUREG-0737: Shift Manning Requirements

The inspector reviewed the licensee compliance to TMI I.A.1.3 to assure regulatory requirements were met. A change to 10 CFR 50.54, issued on July 11, 1983, requires that, <u>effective January 1, 1984</u>, a Senior Reactor Operator (SRO) be present at all times in the control room from which a nuclear power unit is being operated. The purpose is to assure the availability of at least one qualified SRO in the control room without affecting the freedom of the Shift Supervisor to move about the site as needed. The licensee meets the requirement to have a SRO present in the control room at all times. The licensee fulfills the requirement as delineated below:

a. <u>Operating Unit</u> - A unit is considered operating if it is in a mode other than cold shutdown or refueling as defined by Technical Specifications.

b. <u>In the Control Room (Senior Operator)</u> - Spending most of the time in that portion of the control room (for purposes of this definition, Browns Ferry 1 and 2 is considered a single control room) where there is direct and prompt access to information on current plant conditions and where the operator at the controls can be supervised. As duties may necessitate, the senior operator is to have the flexibility to periodically move to other parts of the control room. However, the senior operator should remain, at all times, in a position to provide prompt assistance to the reactor operators when requested. Additionally, this means that the senior operator must either (1) be in sight of or in the audible range of the reactor operators at the controls, or (2) be in the audible range of the control room annunciators.

c. Senior Operator in Control Room - When a unit is operating, a senior operator licensed on that unit must be in the control room at all times. This senior operator can be either a shift engineer or an assistant shift engineer. In addition, when a unit has fuel in the vessel, a licensed reactor operator or senior operator must be at the controls at all times. (For example, with all units operating, a senior operator must be in Units 1 and 2 control room; a senior operator must be in Unit 3 control room; and a licensed reactor operator or senior operator must be at the controls of Unit 1, Unit 2, and Unit 3.)

d. Core Alterations - During core alterations, either a senior operator or an individual with a senior operators licensed limited to fuel handling shall be present to directly supervise this activity. This individual shall have no other duties.

e. Minimum On-site Shift Staffing:

No. of Units Operating	Position	Number Required (on-site)
0	SRO	1
	RO	3(2)
1	SRO	2
	RO	4(2)
2	SRO	3(1)
	RO	5(1)(2)
3	SRO	3
	RO	5(2)

(1) These numbers may be reduced to 2 SROs and 4 ROs if Unit 3 is the nonoperational unit (in cold shutdown or refueling).

(2) RO positions may be filled by an SRO provided the total number of licenses on site requirement is met and at least the specified number of SROs is met.

NOTE: The mix of licensed personnel in this table is such that the senior operator in the control room can be met by either a shift engineer or ASE (SRO) and a relief operator for the reactor operator could be met by another reactor operator (RO), or an ASE (RO or SRO), or a SE (RO or SRO).

NOTE: Temporary deviations from the table are allowable to provide for unexpected situations, such as illness, during a shift. Technical Specification, Section 6.0, manning requirements will apply in this case only.

A satisfactory review of the shift manning requirements per TMI Item I.A.1.3. was conducted by procedural review and control room inspection. This item is considered closed.

11. Reactor Trips

The inspectors reviewed activities associated with the below listed reactor trips during this report period. The review included determination of cause, safety significance, performance of personnel and systems, and corrective action. The inspectors examined instrument recordings, computer printouts, operation journal entries, scram reports and had discussions with operations, maintenance and engineering support personnel as appropriate.

On April 21, 1983, Unit 3 scrammed from 100% power. The scram occurred during the performance of a Surveillance Instruction (SI) for main steam line flow. A full main steam line isolation occurred resulting in the scram. All safety systems operated as designed. Channel 'A' was in test per procedure and a spurious 'B' channel signal was due to a bad flow switch (3-PDIS-1-13B) which was replaced on May 26, 1983. The magnet in the switch was weak which caused the switch to actuate on very minor disturbances.

On May 28, 1983, Unit 3 scrammed from 91% power. Loss of all reactor feed pumps due to low net positive suction head caused by heater string isolation resulted in a low reactor water level scram. All safety systems performed as designed.

On July 22, 1983, Unit 3 scrammed from 97.4% power. Electricians were replacing a burned-out relay (3A-K13C) in the manual trip circuit and shorted one of the leads causing the fuses to blow in the circuit resulting in a scram. All safety systems operated normally.

No violations or deviations were noted in this area.

12. Drywell to Torus Pressure Control

On January 2, 1984, during Unit 1 power operation, the licensee discovered that the drywell to torus delta-pressure monitoring instrumentation (two indicators) was isolated and not fully operable. The inspector reviewed the circumstances related to this event.

Unit 1 has a system to maintain a controlled pressure differential between the drywell and the pressure suppression chamber. This system consists of a compressor connected into the primary containment purge line to form a loop connecting the drywell and the pressure suppression chamber. Nitrogen is pumped from the pressure suppression chamber to the drywell to create the pressure differential. The system is set to establish an operating pressure difference between the drywell and the pressure suppression chamber in the range of 1.1 to 1.35 psid, with the drywell at a higher pressure. A minimum value of 1.1 psid was utilized in the BFN plant unique analysis for the torus blowdown loads. Pressure differential control is operated by either of two independent channels. The purpose of the drywell-pressure suppression chamber pressure differential system is to reduce the thermo-hydrodynamic loads imposed on the pressure suppression chamber during a blowdown following a LOCA.

Initial criticality on Unit 1 was achieved at 6:40 p.m. on December 30, 1983, after the cycle five refueling outage. Unit 1 drywell completed inerting at 6:30 a.m. on December 31, 1983. The drywell delta-pressure indicators in the control room (PDI 64-137 and 64-138) increased to their normal valve of 1.25 psid. This was due to the fact that the isolation root valve that was later found shut was for the low side of the delta-pressure transmitter and normally would read in the "0" pressure range, since the drywell pressure is normally 1.2 psi above the torus pressure. Therefore, the operators did not suspect a problem at this time. During the next two days, the drywell/torus compressor ran excessively due to a compressor head flange leak. This assisted in maintaining the drywell pressure at its nominal range. On January 2, 1984, Surveillance Instruction 4.7.A.4.a, Vacuum Breaker Test, was conducted. During the conduct of the surveillance, the operator observed that the delta-pressure indicators PDI 64-137/138 did not respond as expected. An investigation into the cause of the apparent discrepancy revealed that the instrument root isolation valve to the pressure transmitters 64-137/138 was shut. The valve was tagged out during the cycle five outage for maintenance. On October 18, 1983, the clearance order (83-1232) was cleared and the system valves should have been returned to an in-service condition. In fact, the valve was not returned to service and the tag was not removed from the handwheel.

During pre-startup, system lineups are performed to assure systems are lined up for operation. The isolation valve to PDT 64-137/138 was not on a valve checklist for pre-startup and therefore, the system was not ready for normal operation. During a walkdown of the pressure sensing system for the drywell and torus pressure instruments, the inspector noted that drawing 47W600-133 was inaccurate as it showed the instrument sensing lines between the drywell and torus to pressure transmitters PT-64-135 and PDT 64-137 reversed from the as-installed configuration. As an independent means to determine what torus pressure was reading during the time, the delta-pressure instruments were isolated, the inspector attempted to read the torus pressure on recorder PR 64-50. Unfortunately, the recorder was not energized for the torus pressure trace for operation as required by General Operating Instruction 100-1 prior to plant startup. The recorder was reading 3.5 psig which was not realistic since the typical reading is 0 psig. This parameter is not routinely logged by the operator. Upon opening the isolation valve, all system operations returned to normal. Evaluation of pressure to volume ratios over the three days by the licensee revealed that it was highly probable that the Technical Specification delta-pressure requirement of >1.1 psid was met.

The following violations were identified to the Plant Superintendent on January 13, 1984:

a. Violation of Technical Specification 6.3.A.1 for inadequate procedure in that Operating Instruction 64 (Primary Containment System) did not require the isolation valves to PDT 64-137/138 to be lined up to meet pre-startup requirements. (259/260/296/83-60-03).

b. Violation of Technical Specification 6.3.A.1 for failure to follow procedures in that General Operating Instruction 100-1 (Pre-startup checklists) requires all panel 9-3 recorders be turned on for startup and recorder PR 64-50 torus trace was not energized. (259/83-60-03). This is the second example of Violation (a) above.

c. Violation of 10 CFR 50, Appendix B, Criterion V for an inadequate drawing, 47W600-133, which did not accurately reflect the as-installed configuration for the drywell to torus delta-pressure system. (259/260/296/83-60-04).

d. Violation of 10 CFR 50, Appendix B, Criterion V for failure to follow clearance procedure (83-1232) in that the torus sensing line root valve was not returned to service or tag cleared as required by Standard Practice 14.25. The tag clearance was conducted by an ASE on assignment from the Bellefonte Nuclear Power Plant. (259/83-60-05).

13. Reportable Occurrence

The below listed Licensee Event Reports (LERs) were reviewed to determine if the information provided met NRC requirements. The determination included: adequacy of event description, verification of compliance with Technical Specifications and regulatory requirements, corrective action taken, existence of potential generic problems, reporting requirements satisfied, and the relative safety significance of each event. Additional inplant reviews and discussion with plant personnel as appropriate were conducted for those reports indicated by an asterisk. The following licensee event reports are closed:

LER No.	Date	Event
*260/81-50	10-03-81	Torus hydrogen analyzer, 2-H²M-76-104 inoperable due to moisture in sensing lines.
*260/82-21	07-20-82	Hydrogen analyzer 'B' inoperable due to torus sample valve 2-FSV-76-65 solenoid failure.
*260/82-26	08-19-82	Snubber failed on recirculation system.
*260/82-28	09-21-82	Secondary containment momentary breaching.

*260/82-37	11-22-82	Primary containment local leak rate tests exceeded 60 percent of L_a.
*260/83-05	02-16-83	Primary containment leak rate exceeded allowable due to leakage around flange of 2-FCV-64-20.
*260/83-17	04-09-83	Hydrogen analyzer B inoperable due to moisture in sample lines.
*260/83-18	04-13-83	MCPR exceeded during power change.
*260/83-36	07-04-83	Damaged heat detector TE-39-46B.
*260/83-62	10-04-83	"C" Diesel air start motor engaged during operation.
*260/83-63	10-07-83	Level transmitter for west side SDIV did not initiate trip signal as required, LT 85-45A.
*260/83-65	10-13-83	Violation of T.S. 4.1.c for failing to test redundant scram channel "B" before tripping channel "A".
260/83-66	10-31-83	Hydrogen monitor inoperable due to moisture in sample lines.
260/83-67	10-29-83	RHR loop II flow instrument inoperable, FR-74-64 problem.
*260/83-68	10-21-83	RHR loop II flow instrument inoperable, FR-74-64 problem.
260/83-70	11-03-84	"C" STBY Gas Treatment System HEPA filters had low DOP removal.
260/83-71	11-04-83	Reactor low pressure switch had a setpoint drift.
260/83-72	11-10-83	High flow - pressure instrument on main steam line setpoint drift.
*260/83-73	11-12-83	R-factor out of specification.
*260/83-74	11-10-83	HPCI exhaust rupture disc ruptured.
*260/83-75	11-16-83	R-factor out of specification.

There were no violations or deviations in this area.

14. Lubrication Oil Control

During a routine inspection of Unit 1 on January 23, 1984, the inspector noted that the two Standby Liquid Control (SLC) pumps had different colored oils in the pump crankcase. The 'A' pump contained a dark colored oil and 'B' pump contained a clear colored oil. The mechanical maintenance section supervisor was informed of the difference in oil colors. Oil samples were taken to verify the correct type oil was being used in accordance with the manufacturer's recommendations. The final oil analysis is pending and will be reviewed when the evaluation is completed. As a short term action, the licensee changed out the crankcase oil on all three units' SLC pumps.

Additionally, the inspector reviewed the manufacturer's preventative maintenance oil change recommendations and found that the licensee was not following the recommendations. The manufacturer recommended that an oil changeout be conducted every 2,500 hours or every six months, whichever occurs first. Also, the crankcase is recommended to be cleaned out every year. The licensee does not have an oil changeout or crankcase cleaning program for the SLC pumps.

Designated oils used for various plant safety equipment are stored in an oil storage room in opened 55 gallon drums. The drums are marked with manufacturer name designations, but the licensee cross references the manufacturer's name to a TVA oil classification system. When oil is added to a pump that is low on oil, the mechanic must cross reference the oil drums to the TVA classification system. The potential exists for errors in this area since no quality control verification is required unless more than 20% of the sump capacity is changed out. It would additionally be difficult for a mechanic to determine if 20% was being added without computing volume addition ratios. The oil in the storage room is not arranged by specific classification, but is arranged in a disorganized mixed arrangement. Such a cumbersome system of identification and verification of oil additions has a high probability of leading to errors over time, reducing the quality assurance of pump operabilities.

This item is an unresolved item pending evaluation and further review. (259/83-60-06).