UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA ST., N.W., SUITE 3100
ATLANTA, GEORGIA 30303

Report Nos. 50-259/80-30, 50-260/80-23 and 50-296/80-24

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

Facility: Browns Ferry Nuclear Plant

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

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

Inspection at Browns Ferry Site near Athens, Alabama

Inspectors: P. A. Taylor for — 9-11-80
R. F. Sullivan — Date Signed

P. A. Taylor for — 9-11-80
J. W. Chase — Date Signed

Approved by: H C Dance — 9-11-80
H. C. Dance, Section Chief, RONS Branch — Date Signed

SUMMARY

Inspection on July 1 to 31, 1980

Areas Inspected

This routine inspection involved 153 resident inspector-hours in the areas of operational safety, reportable occurrences, reactor trip followup, plant physical protection, preparations for refueling, plant chemistry and training staff qualifications. IE Bulletin followup.

Results

Of the eight areas inspected no items of noncompliance were identified.

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DETAILS

1. Persons Contacted

H. L. Abercrombie, Plant Superintendent
J. L. Harness, Assistant Plant Superintendent
J. B. Studdard, Operations Supervisor
R. Hunkapillar, Assistant Operations Supervisor
J. A. Teague, Maintenance Supervisor, Electrical
M. A. Haney, Maintenance Supervisor, Mechanical
J. R. Pittman, Maintenance Supervisor, Instruments
R. G. Metke, Results Section Supervisor
R. T. Smith, QA Supervisor
J. E. Swindell, Outage Director
S. G. Bugg, Plant Health Physicist
R. E. Jackson, Chief, Public Safety
R. Cole, QA Site Representative Office of Power
W. C. Thomison, Assistant Results Section Supervisor
A. L. Clements, Chemical Engineer
E. Nave, Shift Technical Advisor
J. D. Glover, Shift Engineer
R. Edmondson, Electrical Engineer

2. Management Interviews

Management interviews were conducted on July 20 and August 1, 1980 with the Assistant Plant Superintendent and selected members of his staff. The inspectors summarized the scope and findings of their inspection activities. The licensee was informed that no items of noncompliance were identified during this report period.

3. Licensee Action on Previous Inspection Findings

Not inspected.

4. Unresolved Items

Unresolved items were not identified during this inspection.

5. Operational Safety

The inspectors 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.

Within the areas inspected, no items of noncompliance or deviations were identified.

6. Reportable Occurrences

The below listed licensee event reports (LERs) were reviewed to determine if the information provided met NRC reporting requirements. The determination included adequacy of event description and corrective action taken or planned, existance of potential generic problems 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.

LER NO.	DATE	EVENT
259/8047	6/4/80	Drywell air sampling vacuum pump pulled an inadequate vacuum.
*259/8048	6/2/80	Main fire header developed leak on sensing line resulting in operation of only one fire pump during repair work.
259/8045	6/2/80	HPCI pump failed to meet minimum flow requirements during Surveillance Testing.
*260/8025	6/17/80	Spare safety valve manufactured by Dressen Industries had cracks in the guide.
260/8022	6/2/80	Turbine first-stage pressure permissive switches exceeded technical specification limits.
*260/8017	3/16/80	Rupture disc on HPCI turbine exhaust line failed.

LER NO. (Continued)	DATE	EVENT
*296/8023	6/17/80	Spare safety valve manufactured by Dresser Industries had cracks in the guide.
296/8020	6/9/80	3B auxiliary oil pump motor tripped because of bearing failure.

The inspectors questions concerning the above reports were satisfactorily answered.

7. Reactor Trips

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

On 6/17/80 unit 1 reactor manual trip occurred at 4:52 p.m. from low power following a startup to investigate a high oil level alarm on a recirculation pump bearing. The reactor protection system and control rod drive system performed satisfactorily. No main steam relief valves or emergency core cooling systems were actuated.

On 6/23/80 unit 1 reactor manual trip occurred at 6:53 p.m. due to oil leaks in the Electric Hydraulic Control (EHC) system. The reactor protection system and the control rod drive system performed satisfactorily. No main steam relief valves lifted. High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) were manually initiated to control reactor water level.

On 6/24/80 unit 2 reactor trip occurred at 1:49 a.m. due to main condenser low vacuum. Air in leakage to the condenser occurred during maintenance on feedwater heater string "C". The reactor protection system and control rod drive system performed satisfactorily. No main steam relief valves or emergency core cooling systems were actuated.

On 6/24/80 unit 1 reactor trip occurred at 4:54 a.m. from a load rejection trip. The trip occurred during turbine control valve testing. An error in re-wiring a pressure switch on 6/23/80 caused malfunction of the switch and produced the trip. The reactor protection system and control rod drive system performed satisfactorily. No main steam relief valves lifted and no emergency core cooling systems were actuated.

On 6/24/80 unit 1 reactor manual trip occurred at 5:33 p.m. from low power due to a partial scram caused by a miswired pressure switch on the control valves. The trip occurred during a turbine control valve testing. An error in re-wiring a pressure switch on 6/23/80 caused malfunction of the switch and produced the trip. This same error caused the trip of 6/24/80, 4:54 a.m. but was not discovered till after the 6/24/80 5:33 p.m. trip. The spurous signal from the control valve pressure switch in conjunction with the control valve testing caused a scram signal for Groups 2 and 3 rods. The operator reset the scram of Groups 2 and 3 rods. The Groups 2 and 3 rods traveled approximately six notches prior to resetting of the scram. The resetting of the scram was possible in less than 10 seconds because only one of two relays in the scram reset circuit energized and both are needed to actuate the 10 sec. time delay. The 10 second time delay is only actuated on a full reactor scram and not necessarily on a partial scram. After noting the resetting of the partial scram because of Reactor Sequence Control System (RCSC) and Rod Worth Minimize (RWM) restraints, a full manual scram was imposed on the Unit. No main steam relief valves lifted and no emergency core cooling systems were actuated.

On 6/28/80 unit 2 reactor trip occurred at 8:49 a.m. due to low condenser vacuum. The control air diaphram on an isolation valve in the line to the steam jet air ejector failed and the valve closed and caused the loss of vacuum. The reactor protection system and control rod drive system performed satisfactorily; one main steam relief valve lifted. No emergency core cooling systems were actuated.

On 7/11/80 unit 3 reactor manual trip occurred at 1211 p.m. from low power in accordance with requirement of IE Bulletin 80-17. Systems performed satisfactorily.

On 7/12/80 unit 3 reactor automatic trip occurred at 9:01 a.m. from low power in accordance with requirements in IE Bulletin 80-17. This reactor automatic trip was induced by de-energizing the average power range monitors (APRMS). Systems performed satisfactorily.

On 7/17/80 unit 2 reactor trip occurred at 907 a.m. on low reactor water level. The cause was a lock-out of the feedwater control when the unit preferred MG set was lost. An over-voltage relay which was sensitive to vibration tripped the MG set output breaker. The reactor protection system and control rod drive system performed satisfactorily. No main steam relief valves lifted and no emergency core cooling systems were actuated.

On 7/22/80 unit 1 reactor trip occurred at 9:08 p.m. due to stop valve closure following a turbine trip. During fire protection testing water was sprayed into an open junction box which contained turbine trip wires connected to a terminal block. The reactor protection system and control rod drive system performed satisfactorily. Three main steam relief valves lifted. No emergency core cooling systems were actuated.

On 7/23/80 unit 1 reactor manual trip occurred at low power in accordance with requirements of IE Bulletin 80-17. System performed satisfactorily.

On 7/24/80 unit 1 reactor automatic trip occurred at 2:28 from low power in accordance with requirements of IE Bulletin 80-17. This reactor automatic trip was initiated by placing APRMs in the inoperable mode.

No items of noncompliance or deviations were identified by the inspectors for the above trips.

8. 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.

On July 11, 1980, an individual who had been boating in the Tennessee River adjacent to the site, abandoned his boat because it sank. He was subsequently picked up by another boater and deposited on the shore next to the security fence around the perimeter of the site. Not seeing anyone around, and in need of a phone to call for assistance, the individual climbed the security fence and entered the radwaste storage building. Upon finding a phone, he called the Shift Engineer who then alerted security personnel. The individual was detained and questioned by Plant Security. The individual was in the security area unobserved for approximately seven minutes. This incident will be further reviewed by Region II security personnel.

With the areas inspected, no item of noncompliance or deviations were identified.

9. Preparation for Refueling

The inspectors observed the receipt and storage of four new fuel elements. The inspectors observed the new fuel being checked for proper welds, serial members, clearances, cleanliness and storage. The inspectors also held discussion with members of the fuel inspection team relating to their job function and qualifications. The Senior Reactor Operator discussed the procedures he was using for inspecting the fuel and the significance of the data he was accumulating on each fuel cell.

The inspectors also reviewed General Operating Instruction 100-3, (GOI-100-3) Refueling Operations, which had undergone a major revision in March of 1980. The review of GOI-100-3 was made to ensure the requirements of the Technical Specification were not violated, the health and safety of the public was not compromised and that the commitments in the Final Safety Analysis Report were adhered to. Previous inspection reports were also reviewed to ensure that commitments made on other refueling inspections were incorporated in the new GOI-100-3. The inspectors had minor comments on GOI-100-3 which were given to plant management for consideration.

Within the areas inspected no items of noncompliance or deviations were identified.

10. IE Bulletin Followup

a. IE Bulletin 79-04

An in-office review of the licensee's response to IE Bulletin 79-04 was considered to be adequate. IE Bulletin 79-04 is closed.

b. IE Bulletin 80-17, Supplement 1 and 2

On June 28, 1980, while shutting down unit 3 for maintenance, 76 control rods on the east side of the core failed to insert fully when a manual scram signal was initiated. (See Inspection Report 50-259/80-28, 50-260/80-21, 50-296/80-22 and Inspection Report 50-259/80-32, 50-260/80-25 and 50-296/80-26 for investigative and testing efforts conducted through July 4, 1980). Additional testing on unit 3 continued after July 4 to determine the mechanism that permitted water to be held up in the Scram Discharge Volume (SDV).

The testing that was conducted consisted of determining the drain rates for the east and west SDV headers with the SDV header vent valves open. It was determined that the west SDV header drained faster and was empty before the east SDV header drained completely. It took approximately 30 minutes to drain the east and west SDV headers starting with the SDV headers completely filled. The drain rates of the east and west SDV headers were also recorded with their respective vent valves shut to determine if the SDV headers would drain with an inadequate vent. The test concluded that the SDV headers would drain but at a greatly reduced rate than with the vents open. It was calculated that an inleakage of less than 6 gpm would be required in order for water to be retained in the east SDV header.

Prior to startup of unit 3 all control rods were scrammed from notch "oo". This test provided additional assurance that the control rods responded to the scram signal. Friction and stall testing was performed on all control rods which failed to insert on June 28. The test was performed satisfactorily and the test data is comparable with the test data recorded after the last refueling outage. 10 control rods from the east side of the core were scram tested to further assure that no abnormalities existed. 5 control rods were selected from those that did not fully insert and 5 control rods from those that did fully insert. The scram test was performed satisfactorily. The reactor was then taken critical and during the heatup the leakage from the scram discharge valves into the scram discharge instrument volume was recorded at 200 psig increment to normal operating pressure. The in leakage was determined to be less than 2 gallons per hour at each increment; The east bank of control rods which failed to insert were scram time tested individually to insure the scram times met Technical Specification. This test was performed satisfactorily with the reactor at normal operating temperature and pressure.

The above testing did not substantiate the mechanism by which water was held up in the SDV headers. Two theories postulated were that there was blockage in the 2 inch drain line from the east SDV header which subsequently was dislodged during the scrams conducted on June 28 and was drained out to the clear radwaste system. The other theory postulated was that improper venting of the SDV headers caused water to be retained in the SDV headers. The blockage which prevented the the venting was subsequentially dislodged during the testing and investigation conducted after the June 28 incident.

On July 11, 1980, a manual scram was performed on unit 3 and the data required by IEB 80-17 was recorded. The inspectors reviewed the data and found no significant problem. On July 12, 1980, an automatic scram was performed in accordance with IEB 80-17. The inspectors reviewed this data and found no significant problems. The above scrams were observed by the inspectors.

On July 23, 1980, a manual scram in accordance with IEB 80-17 was performed on unit 1 and observed by the inspectors. On July 24, 1980, an automatic scram was performed. The test data obtained indicate that the Scram Discharge Instrument Volume drain valve shut in excess of 30 seconds which is above the guidelines recommended by General Electric. The licensee plans to inspect this valve during the next outage. It was also noted that the high level alarm (3 gallons) did not actuate until approximately 50 seconds after the scram. This is after the rod block alarm (25 gallons). The piping diagrams for the scram discharge instrument volume (SDIV) shows the high level alarm piping to connect into the SDIV drain line. As stated above the SDIV drain valve stayed open an excessive amount of time. It was concluded that with water draining from the SDIV drain line a venturi effect on the high level alarm piping had been established. This action prevented receiving the high level alarm until after the SDIV drain valve shut stopping the venturi actions. The high level alarm did come in immediately after the drain valve went shut. The rod block alarm piping is not connected to the SDIV drain line thus was not affected. The licensee has sent a letter to corporate management requesting General Electric to evaluate the design and its effects.

On July 26, 1980, a manual scram in accordance with IEB 80-17 was performed on unit 2 and observed by the inspectors. An automatic scram was performed on the same date as required by IEB 80-17. The test results were reviewed by the inspectors and the only problem observed was that the high level alarm on the scram dischare instrument volume did not actuate. Testing after the scram confirmed the high level alarm switch to be inoperative. The licensee plans to repair the level switch during the next outage.

The inspectors discussed the requirements as specified in IEB 80-17 for initiating the Standby Liquid Control System (SLC) with Shift Engineers, Assistant Shift Engineers and Unit Operators. The inspectors found the licensed operators to be familiar with the Bulletin requirements. One of the conditions in the Bulletin for initiating SLC is if the reactor pressure vessel water level cannot be maintained. The inspector found that the operators definition of this item was varied and vague. This concern was brought to plant management's attention and the regional office. This matter remains open for additional review (80-30-01, 80-23-01, and 80-24-01).

The licensee has instituted a program in which ultrasonic test devices (UT) are installed on the east and west scram discharge volume headers (SDV) for all 3 units. The UT devices are installed on the low points of each SDV header and are connected to an oscilloscope for direct read out. A strip chart recorder continuously records the water level in the SDV headers and the data is periodic review by the Auxiliary Unit Operator (AUO). A local alarm at 1" of water in the SDV headers is also provided. The AUO is required to check each strip chart recorder every 30 minutes for indication of water accumulation in the SDV headers.

The inspectors also examined the licensee actions regarding other portion of IEB 80-17. The areas reviewed consisted of procedures, test data, and discussion with unit operators.

Within the areas inspected no items of noncompliance or deviations were identified.

11. Plant Chemistry

On July 20, 1980, at approximately 8:00 p.m., reactor coolant conductivity in unit 1 was reported to be 1.3 umho/cm^2. This occurred 10 minutes after the "D" condensate demineralizer was placed in service following a change out of the resin. The "D" demineralizer was removed from service upon discovery of the high conductivity. The reactor coolant conductivity had decreased to less than 1.0 umho/cm^2 by 11:00 p.m. on July 20.

On July 21 at approximately 2:15 a.m. reactor coolant conductivity was reported to be 3.2 umhos/cm^2. This occurred approximately 15 minutes after the "J" condensate demineralizer was placed in service following a change out of the resin. The "J" condensate demineralizer was removed from service upon discovery of the high conductivity. The reactor coolant conductivity decrease to less than 1.0 umho/cm^2 by 9:00 a.m. on July 21.

The licensee investigation indicated that the cation and anion powder resin used in the "D" and "J" condensate demineralizer are of the same "lot" number. A chemistry analysis indicates that the cation resin is suspected of containing acidic contaminates. A sample of the "lot" has been sent to the manufacture for analysis and identification of the the contaminates. The inspector will continue to follow the licensee progress in this area.

Within the areas inspected, no items of noncompliance or deviations were identified.

12. Licensee Training Instructors Qualifications

A review was made of the training instructors qualifications for those who instruct plant personnel at Browns Ferry on systems, integrated plant response and transients. There are currently three operations staff personnel who are instructing in these areas and each has a current Senior Reactor Operator (SRO) license from the NRC. There are no current plans to use other than SRO's as training instructors.