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

Report Nos.: 50-321/92-16 and 50-366/92-16

Licensee: Georgia Power Company
P. O. Box 1295
Birmingham, AL 35201

Docket Nos.: 50-321 and 50-366 License Nos.: DPR-57 and NPF-5

Facility Name: Hatch 1 and 2

Inspection Conducted: June 15-19, 1992

Inspector: P. Taylor 8/5/92
for H. L. Whitener Date Signed

Approved by: P. Taylor 8/5/92
for F. Jape, Chief Date Signed
Test Program Section
Division of Reactor Safety

SUMMARY

Scope:

This routine, unannounced inspection was conducted to review licensee actions on previously identified inspection findings and certain aspects of the local leak rate test program.

Results:

In the areas inspected, violations or deviations were not identified.

Licensee action to correct the EDG starting air system air compressor unloader and control valve problems due to moisture condensation was identified as a weakness. The engineering design for rerouting the unloader discharge piping per DCRs issued in 1990 has not been completed and resources are not budgeted for the modification in 1992 or 1993. This condition indicates a lack of aggressive engineering support and timely corrective action.

The licensee's safety assessment of failure to implement change out of the torque

switches in certain Limitorque Operators as recommended by the Limitorque Part 21 Notification dated September 29, 1989, was thorough. No significant safety problem exists as a result of this oversight. The failure to implement the torque switch change out appears to be an isolated case rather than a programmatic breakdown of the Action Item Tracking System.

The local leak rate test program was generally good. Some anomalies identified will be evaluated and corrected by the licensee. These anomalies included:

a. Document justification for Reverse Testing of isolation valves

b. Evaluate the consistency of the draining process valve lineup

c. Correct a discrepancy in the FSAR regarding feedwater valve leak rate tests.

Trending local leak rate valve failures was considered a positive aspect of the leak rate program. Trends show a decrease in the number of failures at each successive outage since 1986.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*O. Fraser, SAER Site Supervisor
*G. Goode, Manager Engineering Support
*J. Hammonds, Regulatory Compliance Supervisor
*A. Huber, Senior Engineer I
*R. King, Engineering Supervisor
T. Metzler, Nuclear Safety and Compliance
*C. Moore, Assistant General Manager
*J. Payne, Senior Engineer I

Other licensees employee contacted during this inspection included engineers and administrative personnel

NRC Resident Inspector

*L. Wert, Senior Resident Inspector

*Attended exit interview

2. Review of LERs Related to Leak Rate Testing

a. LER 50-366/91-008: Main Steam Isolation Valve Local Leak Rate Test Failure

On March 27, 1991, during the Unit 2 refueling outage, the licensee determined that Main Steam Isolation Valves (MSIVs) 2B21-FO22B and 2B21-FO28B were leaking air in excess of the Technical Specification limit of 11.5 scfh per valve. 2B21-FO22B and 2B21-FO28B are the inboard and outboard isolation valves respectively for main steam line (MSL) B at Penetration 7B. Leakage through both of these valves represents a leakage path from the primary containment to the atmosphere under Loss-of-coolant accident conditions.

The leak rate test is performed in two stages. The first stage is a measurement of total leakage performed by pressurizing the volume of piping between the isolation valves and obtaining the leak rate through all valves in the penetration simultaneously. In the second stage the inboard MSIV is backpressured with a water seal so that the leakage measured is through the outboard MSIV and the Leakage Control system (LCS) valve. The total leakage measured was 262 scfh. With the inboard valve sealed the leakage was measured as 92 scfh. This indicates a leakage of 170 scfh for the inboard valve. In a post accident scenario the leakage through penetration 7B would be the limiting value of 92 scfh. Since 92 scfh is within the capacity of the MSIV Leakage Control System the licensee concluded no undue risk to public health and safety would occur.

Based on disassembly and inspection of the valves, the licensee concluded that the root cause of this event was normal equipment wear resulting in a slight degradation of the valve seats. The valves were repaired and leak tested successfully.

After reviewing this matter with the licensee, the inspector concluded that the LER adequately described the event and corrective action was sufficient and timely.

This LER is closed.

b. LER 50-366/91-18: Error In FSAR Results In Missed Technical Specification Surveillance

Plant Hatch's Architect/Engineer (A/E) was directed to review the Unit 2 procedures, Inservice Service Testing (IST) Plan, Final Safety Analysis Report (FSAR) and Technical Specifications (TSs) to resolve any discrepancies concerning primary containment penetrations and isolation barriers. In this review the A/E identified an error in FSAR Table 3.8-5, Penetration Leakage Test. Leak testing of penetration X-228B, a spare electrical penetration, was identified as an integrated leak rate (Type A) test in the FSAR Table. This would be correct only if the penetration blind flange is seal welded. Plant drawings show that, in this case, the blind flange was sealed by a double o-ring arrangement, which requires a local (Type B) leak rate test each refueling outage not to exceed 2 years. Type B tests had not been performed on X-228B.

The A/E informed plant Engineering Support of this condition and a local leak rate test was performed on June 4, 1991. No leakage was identified. This leakage rate test was also construed to meet the requirement to visually verify each 31 days that the penetration is closed.

Type B testing of X-228B has been included in the local leak rate test procedure 42-SV-TET-001-2S. In addition walkdown of Unit 1 and accessible Unit 2 penetrations were performed. The penetration record review will be continued by the A/E.

On January 9, 1992, site engineering identified another spare penetration, X-222A, which was sealed with a bolted blind flange and gasket (LER 50-366/92-01). This type of seal required a Type B leak rate test each refueling outage not to exceed 2 years. No type B tests had been performed on X-222A. In this case, the record review did not reveal the problem. FSAR Table 3.8-5 indicated that the penetration required a Type A test. The plant drawing was consistent with the FSAR in that it indicated a seal welded cap on the penetration. The problem was discovered in the penetration walk down conducted as part of the corrective action for penetration X-228B. Penetration X-222A has been leak rate tested and indicates no leakage. Walkdown of all Unit 1 and accessible Unit 2 penetrations has been completed. Inaccessible Unit 2 penetrations will be inspected in the Fall 1992 refueling outage.

LER 50-366/91-18 and 50-366/92-01 remain open pending completion of the Unit 2 walkdown and correction of plant documents.

3. Local Leak Rate Test Program

The inspector reviewed selected areas of the local leak rate test program as follows:

a. Reverse Testing

ASME Code, Section XI and 10 CFR 50, Appendix J address those valves which may be leak rate tested by pressurizing the valve in a direction different from direction of pressure due to an accident condition (Reverse Testing). Appendix J requires that the test pressure be applied in the accident direction unless pressure applied in the reverse direction is as conservative. Therefore the NRC does not require prior approval to test in a Reverse direction but does require that the licensee justify the conservatism of a reverse test in plant records.

During this inspection the inspector determined that there is evidence that reverse testing has been evaluated by the leak rate test engineer. However, adequate documentation of the justification for reverse testing has not been assembled in a reviewable form. At the exit interview the inspector indicated that the justification including valve types, location, in-line orientation, etc. needs to be clearly analyzed and documented in the plant records. The licensee agreed to document the evaluations in the station records.

b. Draining

The draining of penetrations for the local leak rate test is an essential part of the test. The licensee accomplishes the draining process through the operations clearances rather than through the leak rate test procedure. While draining by a separate procedure is no problem, a preapproved consistent valve line up is needed. Deviation from an approved line up should be reviewed by the leak rate test engineer. At the Exit Interview the licensee agreed to review the clearance process to verify that it serves as an appro. iate procedure.

c. Test Medium

In review of the medium used in local leak rate tests the inspector identified an anomalie in the FSAR. Section 3.8.2.8.2.2.1 (3.8 -49) of the FSAR indicates that the feedwater valves will be tested by applying air pressure to the water filled line. The air leakage would be added into the overall leakage for comparison with the 0.6 La leakage limit.

Table 3.8-7 of the FSAR defines the test of the feedwater valves as a water test. Water leakage is not considered in the 0.6 La leakage limit.

At the Exit interview the licensee agreed to resolve this difference.

d. Trends

The licensee has trended the overall local leakage failures from 1980 to present. These trends show a steady decrease in the number of valve failures from the high in 1986 to present. The inspector considered the trending analysis of valve failures a positive aspect of the local leak rate program.

4. Limitorque Part 21 Notice

In Inspection Report 91-22 dated October 11, 1991, the NRC expressed concern over the failure to fully implement recommendations made by Limitorque under 10 CFR 21. Specifically, it was determined that the torque switches on 20 Unit 2 Motor Operated Valve (MOV) operators had not been inspected for fiber spacers as recommended by Limitorque in a 10 CFR 21 notification dated September 29, 1989. The torque switches had been or were to be scheduled for inspection during the Unit 2 Spring 1991 Refueling Outage, but the inspection had not been performed on 20 of the Unit 2 valves. The required Unit 1 MOV torque switches had been inspected during the Unit 1

Spring 1990 Refueling Outage. The NRC required GPC to explain why the Unit 2 MOV torque switches had not been inspected, what corrective actions were to be taken, and why the uninspected MOVs were not a safety concern.

The licensee responded to the NRC concern in a letter dated December 1, 1991. The failure to inspect the torque switches in 20 valves in Unit 2 appeared to be attributed to personnel error. Inadequate assignment of responsibility between NSAC, maintenance and engineering along with an inadequate turn over by maintenance and engineering personnel who left the company before the Unit 2 outage and an incorrect schedule date were contributing factors in the breakdown of the Action item tracking system. Personnel have been counseled regarding appropriate actions. The inspector concluded that this was not a major program breakdown. Additionally, the licensee provided the NRC a safety assessment for the 20 Unit 2 valves involved. Fifteen of these had been inspected during other maintenance activity. Three of the remaining five are passive valves which do not actuate in the accident condition. The remaining two valves were Plant Service Water (PSW) isolation valves located one in each train of the PSW system. Each of these valves have a redundant isolation valve in series. Additionally, should both valves in one train fail the remaining train provides sufficient cooling to mitigate the consequence of a design basis accident. The inspector concluded that replacement of the remaining torque switches at the next Unit 2 outage is acceptable.

The inspector had no further questions on this matter.

5. Action on Previous Inspection Findings (92701)

a. (Closed) Inspection Followup Item 89-08-03, PSW System Design Pressure

A question was raised during an SSFI in June 1989 with respect to pressure experienced by various pieces of equipment in the Reactor Building which are serviced by Plant Service Water System. Specifically, during an accident wherein the Turbine Building plant service water flow isolates, the PSW pump backs up its performance curve, resulting in system pressure slightly higher than normal. The piping specifications cover the higher pressure by specifying design and maximum pressure at 180 and 190 psig, respectively. However, several components have been identified as having a design pressure lower than that expected during an accident.

In a letter to the NRC dated July 7, 1989 the licensee committed to upgrade the applicable engineering documents to qualify the plant service water (PSW) system components for Unit 1 and Unit 2 to a system pressure of 185 psig. Components which could not be qualified for 185 psig would be modified or replaced as appropriate.

A calculation performed by CVI, Incorporated demonstrated that the air cooling coils for coolers in the Unit 2 Reactor Building Safeguard System were acceptable for a pressure rating of 185 psig. This information was provided to Bechtel who was contracted to recertify the Reactor Building portions of the PSW systems for Unit 1 and Unit 2 to 185 psig. By letter of December 29, 1989 Bechtel advised Georgia Power Corporate Engineering that (per Mechanical Calculations 171 and 575) all components in the applicable portions of the PSW systems could be rated at a system pressure of 185 psig with the following exceptions:

(1) Unit 2 RHR Pump Seal Coolers

(2) Unit 1 service water supply to cooler IT41-B..2B support

Accordingly, design change request (DCR) 2H89-180 for replacement of Unit 2 RHR Pump Seal Coolers A, B, C, and D with units designed for 185 psig was issued and DCR 1H90-007 for modification of support P41-SWH-281A on supply piping to cooler T41-002B in Unit 1 was issued.

The inspector reviewed the Plant Maintenance Work Order documentation demonstrating implementation of DCR-2H89-180 for change out of the coolers in Unit 2 and DCR 1H90-007 for modification of the Unit 1 pipe support. Additionally, by internal memo dated April 5, 1990, Hatch Project Support - Engineering affirmed that Southern Company Services had completed the upgrade to 185 psig of all engineering documents identified in the Bechtel evaluation. Based on the completion of the above actions this issue is closed.

b. (Closed) Inspection Followup Item 50-321, 366/89-08-23, Reliability of Emergency Diesel Generator Starting Air System

During the SSFI inspection in June 1989, the inspectors considered that the number of various component failures raised a question about the Emergency Diesel Generator Starting Air System reliability. The licensee agreed to review this condition and take appropriate corrective action. In a subsequent inspection in August 1991 the inspector found that the licensee had evaluated the starting air system failures and identified the principal failures as unloader and control valve failures and pressure switch out of set point failures. The pressure switches were not considered adequate for the intended service. Four DCRs were issued by the licensee. These included one DCR for each unit to replace the pressure switches with pressure switches appropriate for the intended service and one DCR for each unit to reroute the discharge piping to prevent moisture collection from condensation in the air compressor. It was believed that the condensation caused corrosion of the hydraulic control valves and unloader mechanism resulting in sticking or leaking valves.

During this inspection the inspector determined that corrective action to replace the pressure switches with seismically qualified switches appropriate for the intended function had been completed (DCRs 1H89-259 and 2H89-260). Switch installation was verified by the Nuclear Safety and Compliance group by review of work orders and physical walkdowns. The remaining DCRs, 1H90-095 and 2H90-096, to improve unloader piping were due to be completed in December 1992. The inspector found that the engineering design work for these DCRs had not been completed and resources for the modification had not been budgeted for 1992 or 1993. At the Exit interview the inspector asked management for their intent regarding air compressor moisture problems. Management stated that, due to the cost involved in rerouting the unloader discharge piping, alternative solutions are being studied. Management agreed to provide to the NRC, within three months, the proposed corrective action to resolve the unloader and control valve failure problems and the schedule for implementing these actions. Based on the licensees completion of the evaluation of failure problems in the EDG Starting Air System and partial implementation of the corrective action the inspector considered IFI 50-321, 366/89-08-23 closed. The licensees proposed corrective action and schedule to resolve the unloader failure problems will be tracked through the licensees submittal to the NRC as IFI 50-321, 366/92-16-01: Review the proposed corrective action and schedule to resolve the unloader and control valve failure problems.

The inspector concluded that failure to have resolved an issue identified in June 1989 by June 1992 indicated a lack of aggressive engineering and timely corrective action regarding the unloader failures.

c. (Closed) IFI 50-321, 366/89-08-24: Comparison of Unit 1 and Unit 2 Technical Specifications.

This item addressed the disparity between TS required surveillance for Unit 1 and 2 emergency diesel generators (EDGs). Unit 2 TS incorporated a commitment to Regulatory Guide 1.108, Periodic Testing of Diesel Generator Units Used As Onsite Electric Power Systems, Revision 1 which resulted in more comprehensive surveillance testing requirements for Unit 2 EDGs.

The licensee completed comprehensive evaluations and initiated a TS change to address this disparity. The evaluations performed regarding this issue include a comparison of Regulatory Guide 1.108 line items to Unit 2 TS and a comparison of Unit 1 and 2 TS. Document Change Request, DOCR 89-23, Revision 1 dated November 30, 1989, was submitted on January 10, 1990, to the NRC to request TS changes resulting from the above evaluations.

Pursuant to the application of January 10, 1990, as supplemented January 21 and December 16, 1991 and March 5, 1992, the Nuclear Regulatory Commission issued Amendment No. 178 to Facility Operating License No. DPR-57 and Amendment No. 119 to Facility Operating License No. NPF-5 for the Edwin I. Hatch Nuclear Plant, Units 1 and 2.

The amendments eliminate discrepancies between the plants' TS and Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used As Onsite Electric Power System at Nuclear Power Plants", and conform to the requirements contained in Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," dated July 2, 1984.

The inspector confirmed that revision of plant procedures is in progress and the revised TS will be implemented at the next refueling outage for each unit.

Based on the approved revision of Unit 1 and Unit 2 TSs and the revision of plant procedures in progress, this issue is closed.

6. Exit Interview

The inspection scope and results were summarized on June 19, 1992, with those persons indicated in paragraph 1. The inspector described the areas inspected and discussed in detail the inspection results. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Three open items, 50-321, 366/89-08-03, 89-08-23 and 89-08-24 were closed.

One new item 50-321, 366/92-16-01 was opened to track corrective action on the EDG air starting system.