UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-321/94-05 and 50-366/94-05

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 Nuclear Plant

Inspection Conducted: February 6, 1994 - March 12, 1994

Inspectors: Leonard D. Wert, Jr., Sr. Resident Inspector 4-1-94 Date Signed

Edward F. Christnot, Resident Inspector 4-1-94 Date Signed

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Approved by: Pierce H. Skinner, Chief, Project Section 3B 4-1-94 Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine resident inspection involved inspection on-site in the areas of operations including refueling floor activities and a failed high pressure coolant injection turbine thrust bearing, surveillance testing, maintenance activities, CR 120 relay failures, temporary storage of new fuel assemblies, modifications, Engineered Safety Feature System walkdown, and review of open items.

Results: Two violations and one non-cited violation were identified:

The first violation addressed the failure to promptly identify a condition adverse to quality involving the High Pressure Coolant Injection (HPCI) system. During operation of the HPCI turbine in January and February, 1994, elevated thrust bearing temperatures were indicated. The indications of bearing degradation were not identified or reported for resolution. On March 3, it was determined that the bearing had failed (Violation 50-366/94-05-01: Failure to Identify Elevated HPCI Thrust Bearing Temperatures, paragraph 2d).

The second violation addressed the failure of Control Room operators to comply with HPCI system surveillance procedures. The HPCI system was not shut down when indications of turbine thrust bearing

temperatures exceeded the procedural limits (Violation 50-366/94-05-02: Failure to Follow HPCI Testing Procedure, paragraph 2d).

The non-cited violation (NCV) involved documentation and minor procedural issues associated with the temporary storage of new fuel assemblies (NCV 50-321/94-05-03: Temporary Storage of New Fuel Procedural Issues, paragraph 6).

Two examples were noted in which attention to detail regarding equipment conditions was not appropriate. The inspectors identified degraded conditions involving the filters for the fission product monitor particulate sample pumps. Routine maintenance was not being performed on the filters. The operability of the monitoring system was not directly affected. Routine checks of the monitoring system should have identified the conditions (Paragraph 4c). During routine tours of the main stack, the inspectors noted that movable concrete shielding blocks had unnecessarily remained out of their normal position for extended periods. The licensee was not ensuring that the blocks were replaced after maintenance activities were completed (paragraph 2a).

The inspectors noted overall strong performance during their observations of numerous activities on the refueling floor. Positive observations included consistent use of procedures and high involvement on the part of supervision (paragraph 2c).

The inspectors concluded that the licensee was taking prudent actions regarding several recent failures of relays in important plant systems. Dedicated efforts were completed to determine the scope and further review the issue, including the use of infrared thermography and coordination with other facilities (paragraph 5).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

D. Bennett, Chemistry Superintendent
S. Bethay, Hatch Licensing Manager, Southern Nuclear
J. Betsill, Unit 2 Operations Superintendent
S. Brunsen, Engineer, Nuclear Safety and Compliance
*C. Coggin, Training and Emergency Preparedness Manager
S. Curtis, Operations Support Superintendent
D. Davis, Plant Administration Manager
B. Duvall, Plant Engineering Supervisor
*P. Fornel, Maintenance Manager
*O. Fraser, Safety Audit and Engineering Review Supervisor
*G. Goode, Engineering Support Manager
*M. Googe, Outages and Planning Manager
S. Grantham, Acting Training and Emergency Preparedness Supervisor
J. Hammonds, Regulatory Compliance Supervisor
*W. Kirkley, Health Physics and Chemistry Manager
*C. McDaniel, Supervisor, Plant Administration
*C. Moore, Assistant General Manager - Operations
*J. Payne, Engineer, NSAC
D. Read, Assistant General Manager - Plant Support
R. Reddick, Emergency Preparedness Coordinator
*J. Robertson, Engineering Group Supervisor, PMMS
K. Robuck, Manager, PMMS
*H. Sumner, General Manager - Nuclear Plant
*J. Thompson, Nuclear Security Manager
*S. Tipps, Nuclear Safety and Compliance Manager
*P. Wells, Operations Manager

Other licensee employees contacted included technicians, operators, mechanics, security force members and staff personnel.

NRC Resident Inspectors

*L. Wert
*E. Christnot
B. Holbrook
D. Seymour

*Attended exit interview

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

2. Plant Operations (71707) (93702)

a. Operations Status and Observations

With the exception of power reductions to conduct routine testing, Unit 1 operated at RTP for the entire report period. Unit 2 operated at approximately 70% RTP due to leaking fuel assemblies.

Activities within the CR were monitored routinely. Inspections were conducted on day and on night shifts, during weekdays and on weekends. Observations included control room manning, access control, operator professionalism and attentiveness, and adherence to procedures. Instrument readings, recorder traces, annunciator alarms, operability of nuclear instrumentation and RPS channels, availability of power sources, and operability of the SPDS were monitored.

CR observations also included ECCS system lineups, containment integrity, reactor mode switch position, scram discharge volume valve positions, and rod movement controls.

Plant tours were taken throughout the reporting period on a routine basis. The areas toured included the following:

Reactor Building and Roof	Diesel Generator Building
Fire Pump Building	Intake Structure
Station Yard Zone	Turbine Building and Roof

Paragraph 2c of this report discusses observations of refueling floor activities. Paragraph 4c discusses observations of poor conditions of the fission product monitoring system particulate sampling pump filters.

During a routine tour of the main stack, one of the inspectors noted that several shielding blocks were removed from their normal position. The blocks make up part of the floor on the ground level of the stack and apparently were removed to conduct maintenance on offgas system components which are located below the blocks. The inspector had noted previous instances in which the blocks had been removed for long periods of time (at least several weeks). Although the work which necessitated the removal of the blocks was completed, the blocks were not reinstalled. After the inspector had discussed the issue with the manager of HP and Chemistry, the blocks were reinstalled.

The inspectors reviewed available documentation to determine the significance of the shielding blocks not being properly controlled. The issue was discussed with inspectors in the regional office. The blocks are addressed in the FSAR as an access control barrier. Plant drawings and the FSAR also describe radiation "zones" which incorporated the shielding effect of the blocks. After discussions with HP supervision, the inspectors concluded that, although the blocks were not expeditiously replaced after work was completed, sufficient surveys and radiological controls were applied through routine HP practices and no increased exposure issue existed. The radiation "zones" discussed in the FSAR are not relied upon for current dose control. The inspectors noted that the area had been designated by radiation area boundaries and signs requiring use of an RWP before entry. The licensee stated that the normal practice was to survey the area as the blocks were lifted and at periodic intervals afterwards. Licensee management determined that MWOs which require the blocks to be removed should also contain directions to ensure their replacement, and corrective actions were initiated.

b. Refueling Floor Activities

The inspectors observed refueling floor activities at periodic intervals throughout the report period. Several of the observations were conducted on evening and night shifts. During the period of February 21-24, three major activities were in progress simultaneously on the refueling floor. The activities included: inspection of new fuel, reconstitution of some of the new fuel bundles, and transfer of spent fuel between the two spent fuel pools.

GE Field Disposition Instruction 0116-12900 and GE Procedure PQP 8.6 (Revision 9): Bundle Reconstitution at the Site, were the procedures used for the reconstitution. The inspectors verified that these procedures had been reviewed by the Hatch PRB and that the work was being performed as required. Procedures 42FH-ERP-012-0S: New Fuel and New Channel Handling, 42FH-ERP-014-0S: Fuel Movement, 51GM-MLH-004-0S: Heavy Loads Movement Procedure, and 34FH-OPS-001-0S: Fuel Movement Operation, contained the instructions for the other activities in progress and were reviewed by the inspectors. The inspectors noted that a SNC representative was closely monitoring the reconstitution process. Meticulous verification of the relocated fuel pins was observed.

All observed rigging, lifting, and inspection of the new fuel bundles was performed carefully and in accordance with the procedures. Active supervision by the reactor engineer was noted. The refueling coordinator was also closely following the activities. The movement of spent fuel and control rod blade guides between the fuel pools was performed as required. The inspectors noted that when refueling bridge or grapple problems occurred, the SRO on the bridge ensured that procedural guidelines were followed and conservative actions were taken. Discussions with personnel indicated that the plant manager had also visited the refueling floor several times during the period. The inspectors noted that workers had to remain alert in order to ensure that movement of new fuel by the overhead crane (hoist) did not interfere with movement of the refueling bridge.

Two of the inspector's tours were conducted during heavy rainstorms and some leakage into the building was noted. The rain apparently leaked in through small cracks in the tornado relief vents and small openings at the connecting joint between the two reactor buildings. Cracks in the acrylic lens on the tornado vents is a recognized problem which is being addressed by a modification. Paragraph 7 of this report discusses the vent modification in more detail. During a tour of the RB roof, the inspectors noted that some of the metal protective covering over the seam between the two RBs was missing, and some deterioration of the membrane material in the area of the seam was observed. An engineer informed the inspectors that a DC had been written to address the problems. The RB roofing contractor was scheduled to inspect the roofing on March 2. The inspectors verified that secondary containment testing was completed satisfactorily prior to commencement of fuel movement.

Throughout this period of observations the inspectors noted that the applicable procedures were complied with and the various activities were conducted in a controlled and professional manner. Paragraph 6 of this report discusses some minor procedural issues identified on February 28 by the inspectors involving storage of new fuel bundles in the dry storage vaults.

c. Secondary Containment Integrity Issue

On February 9, at about 6:45 pm, a degradation of Unit 1 secondary containment was identified by the licensee. A supplementary fuel pool cooling system was being installed on the 158 foot elevation in the Unit 1 RB. The piping for the secondary cooling loop of the system penetrates the RB wall. The pumps and heat exchangers for the secondary loop are located outside the RB on the roof of the railway entrance airlock. At about 6:00 pm, workers removed a blank flange that was mounted on the outside piping. An open one inch diameter socket weld on the top of the pipe about five feet inside the RB resulted in an open path from inside the RB through the open end of the pipe. The socket weld was partially taped over so the leak was not large. During the oncoming shift briefing a worker mentioned the open sockets. At approximately 6:45 pm the opening was discovered and the blank flange was reinstalled.

The inspector discussed the incident with several engineers involved in the project and walked down the involved piping. The piping was examined and it was noted that two blank flanges had been inserted into the piping just inside the RB to serve as the integrity boundary. The flanges were also tagged in place. The removal of the flange had been planned and was performed in a controlled manner. One of the engineers and an operations SS had walked down the interior piping prior to the flange removal. The intention was to shift the boundary to two closed valves in the piping inside the RB. The open socket, located between the valves and the RB penetration, was on the top of the piping and was not seen during the walkdown. Additionally, the socket had been installed prior to the piping being brought into the RB. The drawing being referred to by the engineer did not have the socket identified on it.

Unit 1 TS 3.7.C requires secondary containment integrity to be met during all modes of operation. Unit 2 TS also require Unit 1 RB integrity. The definition of secondary containment integrity requires that the RB be intact. The TS require that if integrity is lost, it shall be restored within four hours. The inspectors reviews indicated that the integrity had been restored within one hour. Additionally, the inspector examined the recorder printout for secondary containment pressure and discussed the issue with the CR operators on duty during the incident. It was noted that each unit had one train of SBGT in operation at the time the flange was removed. No decrease in the negative pressure of containment was observed. The differential pressure remained in excess of 0.25 inches of water during the entire episode. The inspector also verified that the required testing of secondary containment integrity, after the breach had been sealed, was completed satisfactorily.

Prior to this problem, the inspectors had periodically toured this work area and reviewed secondary containment controls. No other deficiencies had been noted. The safety significance is negligible. The basis of the requirement to maintain the RB integrity is to ensure that the required negative pressure can be maintained. In this instance, negative pressure was maintained. While a more rigorous inspection of the interior piping would have identified the open socket and prevented the problem, the inspectors concluded that the flange removal had been performed in a controlled manner.

d. Hatch Unit 2 HPCI Thrust Bearing Failure

On March 1, 1994, during surveillance testing in accordance with Procedure 34SV-E41-002-2S: HPCI Pump Operability, high temperatures were noted on the HPCI turbine thrust bearing. After testing of the associated temperature recorder and discussions with the turbine vendor, the licensee removed HPCI from service on March 2 and inspected the thrust bearing. The bearing had extensive damage. The inspectors had recently observed several consecutive HPCI tests, but did not monitor this test. The inspectors noted discussion of the bearing temperature issue at the routine morning management meeting on March 2. The inspectors reviewed the temperature recorder indications and applicable procedures and monitored the licensee's investigation. The investigation included an ERT which was assisted by several highly experienced contractor HPCI system/turbine technical experts.

At approximately 9:20 am on March 1, routine testing of the Unit 2 HPCI system was in progress in accordance with Procedure 34SV-E41-002-2S. Prior to the testing, the operators discussed a thrust bearing temperature "spiking" problem which had apparently occurred on previous recent HPCI tests. The SOS was also aware of the "spiking" issue. The temperature of the thrust bearing is indicated on the back of a CR panel on recorder 2E41-R605. After the turbine had operated for several minutes, the elevated temperature was noted by the SS. He initially thought that the recorder indicated bearing metal temperatures and not oil temperatures. Limitation 5.2.5 of 34SV-E41-002-2S states that if bearing oil reaches 160 °F, the pump must be shutdown. The SS then reviewed drawings and determined that the recorder indicated oil temperatures. Shortly after he had completed this review, the system engineer completed his reviews of local indications, and HPCI was secured.

The inspectors reviewed the printout of the recorder indications acquired during the testing. The inspector noted that the thrust bearing temperature started increasing rapidly as soon as the turbine was started up. Point 24 (thrust bearing) reached 440 °F within 2 to 4 minutes. Other oil temperatures were normal. The thrust bearing temperature peaked at about 450 °F. The bearing temperature was greater than 440 °F for five minutes and above 160 °F for at least 20 minutes. The turbine was operated for about 30 minutes. There is a CR front panel annunciator on high temperature on the discharge of the oil cooler. This temperature did not reach the alarm setpoint.

After the test was completed, the system engineer, who had monitored the test in the HPCI room, informed the CR that the HPCI oil system pressure should be adjusted. The CR operators informed the engineer of the bearing temperature issue at that time. Review of the local gauges by the operators and the system engineer indicated that the thrust bearing oil pressure was slightly low (about 7.5 psig versus the normal 10-12 psig). As discussed in IR 50-321,366/94-02, bearing oil pressures were adjusted after the most recent Unit 1 HPCI run, and were reviewed by the inspectors. The oil pressures were not low enough to effect operability and the system engineer stated that adjustments are made at infrequent intervals primarily to improve oil system performance.

After additional review and testing of the bearing temperature recorder, HPCI was declared inoperable at 1:30 pm on March 2, and more investigation into the failed bearing was initiated. The inspectors discussed the issue with operations management and emphasized the seriousness of the incident. Violation 50-321/93-06-02: Failure to Follow EDG Alarm Response Procedure, was issued in June 1993, and addressed a similar incident that was identified by the inspectors during an EDG surveillance test. Other examples involving failure to adhere to procedural requirements for given indications have been identified.

The inspectors observed portions of the repair and investigative activities. Numerous discussions were held with the technical experts, other ERT members, and management regarding resolution of the issue. The inspectors divided the issues into two primary areas; the technical aspects of the bearing failure, and operator performance issues.

The following is a summary of the important factors regarding the technical issues of the bearing failure:

- The bearing is a Kingsbury thrust bearing which contained six shoes on the "active" side (normal loading) and three on the "inactive" (secondary loading) side. The "inactive" side received the most damage with the babbitt completely removed from the shoes. One of the inspectors observed the disassembly of the rotor components and noted grooving of the thrust collar on the inactive side and discoloration of the components due to extreme heat.

- According to available information, there has been no other failures of HPCI thrust bearings in the industry.

- Dimensional checks indicated that the components had been assembled with the proper clearances. No problems with other bearings or pump gearboxes were detected. The thrust bearing had been replaced in November 1992, after routine inspection had indicated some slight wiping of the bearing. Reviews of the associated work documents did not disclose any deficiencies in the replacement activities.

- After removal of the HPCI turbine rotor, a detailed examination of the thrust bearing area was conducted. It was identified that the channel which supplied oil to the outboard or nonactive side of the bearing had not been fully drilled during the original manufacturing process. The approximately 1/4 inch diameter oil supply channel had not been completely drilled through and a portion of the channel was only about 1/8 inch in diameter. This could have permitted very small particles to block or throttle the oil supply to the bearing. The channel was drilled out to the proper diameter. It was noted that upstream of the channel, in the supply line, is a 7/32 inch orifice.

- The oil in the HPCI reservoir was completely drained and filtered. No material other than that attributable to the failed bearing was found. Analysis of the oil indicated that the oil was in good condition and no significant impurities were present.

- The inspectors performed a detailed review of data from HPCI operations since the bearing replacement was conducted. Vibration levels and thrust bearing temperatures had been increasing noticeably over the last four HPCI tests but vibration had not been high enough to suspect operability problems.

- After extensive investigative actions and reviews, a postulated cause of the bearing failure was established. It is believed that a degradation in the coupling between the turbine and the pumps was not allowing shaft movement as the shaft expanded after being exposed to steam. Degradation of the coupling's engagement surfaces resulted in the coupling not sliding under high rotational loading. This resulted in high force pushing the thrust bearing collar against the inactive side surfaces. The behavior of the thrust bearing temperatures as indicated on the recorders supported this theory. The thrust bearing was replaced with an upgraded type which consists of six shoes on both sides of the bearing. It was concluded that this replacement, along with the drilling of oil passage, would enable the thrust bearing to withstand more pressure in the future. The coupling was also replaced. Some pitting of the engagement teeth on the coupling was noted.

The licensee plans to send the coupling to the vendor for additional analysis.

The following issues were noted regarding personnel performance issues:

- The temperature recorder printouts indicated that the thrust bearing temperature has been increasing rapidly during HPCI starts for at least several months prior to this test. The inspector noted that in December 1993, the temperature "spiked" to a value above 160 °F for about 30 seconds. In the January and February tests, the temperature exceeded 160 °F by increasing amounts and for longer time periods. No DCs had been written to address the indications. No comments were made on surveillance testing records. Information indicated that the information was known by several operations personnel. Despite this information, the temperature recorder was not closely monitored during the March start of the turbine. It should be noted that the procedure requires checking of the temperature values after a number of other activities are completed, so typically the temperature values were probably decreasing and below 160 °F when checked by the operators. During short duration spiking, the temperature recordings may have been difficult to assess, but the longer duration temperature excursions which occurred during the January and February testing were clearly in excess of 160 °F.

- The bearing vibration levels had also been increasing during the testing, and the increase had been noted by maintenance engineers. In October 1993, the vibration level was recorded as 0.069 inches/second; during the February test, the level was 0.293 inches/second. Some investigation had been planned for the upcoming outage.

- The system engineer had not been informed of the problem until after the March 1, 1994 testing. The engineer did not routinely examine the bearing recorder traces after testing. He monitored bearing oil pressures closely and relied on the data recorded in the surveillance procedures by the operators for bearing temperature monitoring. The inspectors have previously noted (IR 50-321,366/94-02) that this particular engineer is proactive regarding deficiencies in the HPCI system.

- The Unit 2 SS, despite clear indications that bearing temperature was in excess of 160 °F, did not direct the shutdown of the turbine.

Licensee management considered the personnel performance side of this issue to be very serious. Management has stated that the performance of the SS did not meet expectations in several areas. The SOS, SS and plant operator were temporarily removed from licensed duties. Additional disciplinary actions were taken.

The inspectors concluded that the failure to identify the eminent failure of the thrust bearing despite clear indications of degradation was the most significant aspect of the incident. The failure to shutdown the turbine during the March test was considered a significant failure to follow procedure. Several similar examples involving failure to complete actions as required by plant or equipment conditions have been identified.

The inspectors closely followed the licensee's assessment of operability of the HPCI turbine given the degraded condition of the thrust bearing. The inspectors discussed operability with both the licensee's ERT members and the technical experts.

Through most of the review of the event, the licensee's position was that the turbine was operable up until March 1. While the bearing was degraded during the February test, it was felt that there was babbitt material on the bearing surfaces. The inspectors had questioned the ability of HPCI to restart after the February test. The turbine and the pumps are designed to operate without significant axial thrust once the system is started and running. Steam is input onto turbine wheels via a balanced emission system, pumps are "separated" from turbine via a coupling. The inspectors noted that significant clearance margin is available before the steam jets would not impact the turbine wheel as designed. The concern would be limited to the initial or "cold" start where the shaft would expand faster than the casing, resulting in forces on the thrust bearing. Once the system is running, this force is reduced.

Later in the review process, the licensee's position on operability was revised. After the February test, an additional cold start would have resulted in a "steel-to-steel" interfacing on the thrust bearing surfaces (as occurred after the March test). If subsequent "hot" restarts would have been necessary, the technical representatives could not state that the HPCI system would have performed its function. Damage to the governor end of the shaft due to clearances may have occurred. It is entirely possible that the system would have operated as required.

The inspectors reviewed the operability of the other ECCS systems during the time that HPCI was degraded. On February 6, the 2B train of core spray was removed from service for approximately 18 hours. On February 8, the 2A loop of RHR was inoperable for about 48 hours.

The inspectors noted that while the FSAR mentions the ability of HPCI to restart, no specific reference to restart capability was noted in the FSAR Chapter 15 accident analyses. Additionally, it should be noted that the restarts would be "hot" starts of the system. If the system was performing as designed, the thermal effects and forces on the thrust bearing would not be large.

Repairs to the bearing and coupling replacement were completed on March 9, 1994. After additional corrective actions to resolve a problem with the exhaust steam line drain pot, the HPCI system was returned to an operable status on March 10, 1994.

Criterion XVI of Appendix B of 10 CFR 50 requires that measures be established to assure that conditions adverse to quality are promptly identified and corrected. Procedure 10AC-MGR-004-0S: Deficiency Card System, states that a DC will normally be written if "response/parameters are not normal during operation, maintenance, or testing." The temperature "spiking" problem was not communicated to the system engineer or management. The inspectors concluded that the procedures and management's expectations required that a DC be initiated for the observed parameters. This violation is addressed as Violation 366/94-05-01: Failure to Identify Elevated HPCI Thrust Bearing Temperatures.

The failure to shutdown the turbine as required by limitation 5.2.5 of Procedure 34SV-E41-002-2S: HPCI Pump Operability, is addressed as Violation 50-366/94-05-02: Failure to Follow HPCI Testing Procedure. Licensee management recognized that this incident was similar to previous issues, but attributed it primarily to the performance of the few individuals involved. Management concluded that, in general, procedural compliance has significantly improved. Recent NRC inspections have also noted an overall increased awareness on procedural compliance, with some exceptions noted in previous reports.

Two violations were identified.

3. Surveillance Testing Observations (61726)

Surveillance tests were reviewed by the inspectors to verify procedural and performance adequacy. The completed tests reviewed were examined for necessary test prerequisites, instructions, acceptance criteria, technical content, authorization to begin work, data collection, independent verification where required, handling of deficiencies noted, and review of completed work. The tests witnessed, in whole or in part, were inspected to determine that approved procedures were available, test equipment was calibrated, prerequisites were met, tests were conducted according to procedure, test results were acceptable and systems restoration was completed.

The following surveillances were reviewed and witnessed in whole or in part:

1. 42SV-R42-003-0S: Battery Inspection (Attachment 2)
2. 52SV-R42-001-1S: Unit 1 Battery Pilot Cell Surveillance
3. 52SV-E41-003-0S: HPCI Turbine Mechanical Overspeed Trip Functional Test and Calibration
4. 57SV-MNT-020-2S: Response Time Test of Channel A Relay Logic (validation)

The testing of the HPCI overspeed trip was conducted with reactor steam following extensive corrective maintenance on the HPCI system. Usually, this testing is performed with lower pressure auxiliary steam. The inspectors noted that the testing was conducted in an appropriately cautious and deliberate manner. Thorough briefings and procedural reviews were completed. Contingency actions were discussed during preparations. A high priority was placed on communications between the different working groups during the testing. Several unexpected problems were encountered during the testing. The inspector noted that the CR operators maintained good control of the testing. The Unit 2 SS demonstrated good oversight of the testing.

No violations or deviations were identified.

4. Maintenance Activities (62703)

a. Maintenance Observations

Maintenance activities were observed and/or reviewed during the reporting period to verify that work was performed by qualified personnel and that approved procedures in use adequately described work that was not within the skill of the trade. Activities, procedures, and work requests were examined to verify proper authorization to begin work, provisions for fire hazards, cleanliness, exposure control, proper return of equipment to service, and that limiting conditions for operation were met.

The following maintenance activities were reviewed and witnessed in whole or in part:

1.	MWO 1-94-1046	Trouble Shoot, Repair and Calibrate EDG Fuel Oil Day Tank Level Indication
2.	MWO 1-94-1485	Replace Servo and Calibrate Temperature Recorder 1E41-R605 (RHR WATER TEMP - HPCI TURB/PUMP)
3.	MWO 1-94-1454	Support Engineering Investigation of HPCI Room Cooler Low Water Flow
4.	MWO 2-94-599	Disassemble, Inspect, Repair and Reassemble Unit 2 HPCI Turbine
5.	MWO 2-94-0061	Repair Coolant Leak on Security EDG Radiator

Paragraph 2d discusses observations of the HPCI turbine repair activities.

The inspector continued to followup on the repairs to the damaged electrical cables and buried conduit raceway discussed in IR 50-321, 366/94-02. The PMMS manager stated that cable splicing repairs were completed. The inspector noted that the Glycol pump pressure indicator in the control room was functioning and the B train valve position was indicating properly. Additional jack hammering activities were necessary in order affect rebar repairs. All observed activities were supervised and controlled.

The inspectors reviewed the licensee's plans for major maintenance activities during the Unit 2 refueling outage scheduled to begin on March 16, 1994. Recent LERs, IRs, Bulletins, INs and other documents were reviewed to ensure that issues of interest requiring resolution or corrective actions are included in the licensee's plans. All items were addressed.

b. Repairs to Yard Drainage System

IR 50-321,366/94-02 documented a concern involving the licensee's controls of excavation activities. The inspectors noted that a hole had been discovered next to the Unit 2 Reactor/Radwaste Building Chill Water system Cooling Tower. The hole was approximately 12 feet deep and ten feet in diameter. It was determined that a seal on a drain pipe, part of the general plant yard drainage system, had deteriorated. The drain pipe penetrated into a six foot round by 12 foot deep concrete catch basin. Two other pipes also penetrated into the catch basin. Over an extended period of time water has been leaking from the drainage system through the failed seal and eroding the soil from around the pipe. The inspector discussed the problem with an excavation coordinator. The inspector concluded from the observations and discussions that the coordinators were well aware of what caused the hole and what corrective actions were necessary to fix the seal and fill the hole. The coordinators were also knowledgeable of what underground drawings were applicable to the area and which ones would be updated. The inspector concluded that these excavation activities were controlled more appropriately than the instances discussed in IR 50-321,366/94-02.

c. Particulate Monitoring Systems Sample Pump Filters

IR 50-321,366/94-02 contained a brief discussion of the installation and maintenance of filters for radioactive effluent monitoring system sample pumps. The filters consist of paper type elements installed inside glass jars. The inspectors had noted that one filter associated with the main stack monitoring system appeared to be installed in an incorrect orientation. Additionally, the inspectors had questioned the routine maintenance of the filters. Labeling on the glass jars states that the filter elements should be periodically inspected and/or changed out. The inspectors were informed that Procedure 52PM-D11-001-OS: Main Stack Gas, Reactor Building and Recombiner Building Vent Sample Pump Maintenance, contains the appropriate requirements. The inspectors reviewed the procedure and verified that the filters are changed out at 3 month intervals. This frequency seems appropriate since the inspectors have not noted any degraded filters in the above monitoring systems.

During a routine tour, one of the inspectors noted that the filters (same type as discussed above) installed on the Unit 1 FPM particulate sample pump were significantly degraded. The filter element on the pump suction line appeared to have mold on it. The filter element on the pump discharge had fallen off of the piping and was resting on the bottom of the jar. The discharge filter jar contained a significant amount of black dust. The Unit 2 FPM particulate sample pump has similar filters, but metal retaining jars are used so the condition of those filters was not determined. In response to the inspector's questions, the licensee confirmed that the filters on the FPM systems are not routinely changed out or inspected.

The inspector reviewed the available vendor information on the FPM systems. Routine maintenance of the filters is not addressed except a statement that new filters are supplied along with new pumps. Apparently, the filters are intended to protect the sample pump and to prevent carryover of carbon from the pump vanes into the system. The inspectors reviewed the maintenance records of the sample pumps. It was noted that the Unit 1 and Unit 2 pumps had been replaced several times over the last three years. The records indicated that the filters were changed out each time the pump was replaced.

Operation of the FPM particulate monitoring systems are required by TS. The inspectors noted that the particulate monitoring system flowrates and other parameters are monitored daily by chemistry personnel. Additionally, an alarm will actuate in the CR if sample flow decreases to an unacceptably low value. The inspectors concluded that inadequate maintenance on the filters did not directly effect the operability of the FPMs, but could be a factor in the overall reliability of the sampling systems. Additionally, the poor condition of the installed filters indicated a lack of attention to detail on the part of personnel that monitor the systems. The licensee reviewed the issue and concluded that routine inspection and/or replacement of the filter would be appropriate. At the close of the report period, the licensee was developing procedural guidance for periodic replacement of the filters.

No violations or deviations were identified,

5. GE CR 120 Relay Coil Failures

In the last several months, three failures of relays/coils in CR circuits have occurred at Hatch. One was a HFA type relay which failed due to bobbin cracking which resulted in winding damage. This is a recognized failure mechanism. Hatch had made a decision to not replace this non-safety related relay and it reached end of life. The other failures involved continuously energized GE CR 120 type relays. The most recent case involved a coil failure which blew a fuse and resulted in an ESF actuation. A 10 CFR 50.72 notification was made. The licensee initiated a review regarding potential common mode failures. There have been similar failures at several other sites Hatch has about 1700 of these relays in safety related applications in the plant. The licensee's review of NPRDS data since 1984 indicates that 23 failures of CR 120 relays have occurred at Hatch that involved relay or coil degradation. Hatch has performed a safety assessment of the coil failures which concluded that there is reasonable assurance that the safety systems will perform their intended functions. Replacement of some coils is planned. The assessment relies heavily on "fail safe" design of the safety systems.

The inspector discussed the coil failures with a GE engineer. He stated that GE has been evaluating the issue and is currently determining the most appropriate means to address the issue. One potential contributing factor is that the relays may have a 15-20 year lifetime depending on its application/installation. The inspector was informed that a draft SIL will be issued shortly on the issue which will describe how to test the coils/relays and determine their remaining life. Hatch is also utilizing infrared thermography in attempts to detect potential failures. Some information indicates that the voltage supplied to the coils may play a role in the failures. While failures of the coils have thus far left the systems in safe conditions, it appears that failures could affect adjacent equipment. The inspector was informed that the issue is still under review for 10 CFR Part 21 reportability.

The inspectors concluded that the licensee is taking appropriate actions to determine the cause of the failures and address the issue. The efforts have involved coordination with other utilities and GE. The inspectors will continue to follow the licensee's actions.

No violations or deviations were identified.

6. Procedural Problems Involving Temporary Storage of New Fuel in Dry Storage Vault (71707)

During a routine tour of the refueling floor on February 28, one of the inspectors identified some concerns involving the temporary storage of new fuel bundles in the dry storage vault. The inspector entered the refueling floor area at about 4:40 pm and noted that several bundles of new fuel had been moved into the dry storage vault. The inspector observed that the bottom of the vault appeared to be wet and a small puddle was visible on the floor of the vault. The inspector confirmed these observations with a flashlight. The reactor engineer on the refueling floor was immediately informed and he subsequently informed the refueling floor coordinator. Neither of these individuals were aware of the water in the bottom of the vault. The inspector questioned the individuals about the source of the water and the status of the vault drains. The reactor engineer and the refueling floor coordinator indicated that they did not have that information. The inspector also immediately informed the SOS of the observations. The water did not entirely cover the vault floor and was far below the level of the racks in which the fuel was stored.

Several minutes later, the offgoing (dayshift) refueling floor reactor engineer provided additional details to the inspector regarding the water. The engineer stated that upon lifting off the concrete plug over the vault, water was noted on the plastic sheeting over the rack (located inside the vault) and the floor was dry on both sides of the rack. When the plastic was removed from the rack, the water fell to the vault floor. The engineer stated that he had concluded that there was no water leaking into the vault and that the fuel could be stored in it. Although this information alleviated the possibility of an immediate safety concern, the inspector remained concerned about several procedural aspects of the issue.

Procedure 42FH-ERP-012-OS: New Fuel and New Channel Handling, contains the applicable guidance involving loading of new fuel into the dry storage vaults. Special requirement 4.3.13 states that the fuel must NOT be placed in the new fuel storage vault IF the vault is NOT dry. Step 7.1.10.3 requires independent verification by visual inspection that the storage vault is dry and documentation on a form similar to Attachment 3 (New Fuel Storage Vault Log). Steps 7.1.10.1 through 7.1.10.3 require that the polyethylene sheet be removed from the storage rack prior to the inspection to determine that the vault is dry.

The inspectors discussed the issues with licensee management and some of the involved personnel. The applicable regulatory requirements were reviewed in detail. The inspectors noted that the FSAR specifically states that the vault can be completely flooded with water and the effective multiplication factor would be maintained below 1.00. The only safety concern would be if a spray or mist was admitted into the vault. The onshift operators verified that the vault drain valves were locked open as required. No additional fuel was loaded into the vault and it was dried out. The licensee attributed the water on top of the plastic to frequent floor cleaning activities.

As a result of the reviews of the issue, the following concerns were noted:

- The independent verification of the vault condition was signed by the reactor engineer who had not been aware of the water on the floor until the inspector pointed it out. After discussion with the individual and supervision, the inspectors concluded that he had performed the verification but not with sufficient detail to note the water on the floor of the vault.

- The independent verification was documented on the procedure attachment after several bundles had been loaded into the rack. Step 7.1.10.3 requires that the documentation be performed prior to positioning the bundles in the vault.

- The reactor engineer who had interpreted the requirement for a "dry" vault to mean "not flooded" did not document any comments or notes explaining the condition of the vault on the procedure. Additionally, the status of the vault had apparently not been discussed in detail during the turnover of the refueling floor reactor engineers.

The inspectors concluded that there was no direct safety issue involved in the incident. While the purpose of the procedural requirements had been complied with, procedural adherence had not been as rigorous as expected. More detail should have been applied during the independent verification process. The failure to properly document the independent verification is a violation of the procedure. Independent verification must always be performed and documented as required. This NRC identified violation is not being cited because the criteria specified in section VII.B of the enforcement policy were satisfied. This issue is identified as NCV 50-321/94-05-03: Temporary Storage of New Fuel Procedural Issues. The licensee had discussed the procedural issues within the engineering department in detail. Revision of the procedure to remove some of the specific steps which are not necessary is planned. The inspectors also had made positive observations regarding the overall performance of reactor engineers on the refueling floor (paragraph 2b of this report).

One NCV was identified.

7. Modifications (37700, 37828)

The inspector reviewed, observed and discussed several of the modifications started and planned for the Unit 2 outage. Among the modifications were:

DCR 93-62	Replace Unit 2 Station Service Batteries 2A and 2B
DCR 93-31	Install Alternate Spent Fuel Cooling
DCR 93-09	Install RPS MG Set Time Delays
DCR 92-137	Remove Exiting RHRSW Air Release and Replace With 4 New Valves on Minimum Flow Line
DCR 92-164	Relocate Valve 2E41-F006, HPCI Pump Discharge Valve
DCR 90-130	Replace RHRSW Valve 2E11-F068A and B with DRAG Valves
MDC 94-5001	Replacement and Modification of Reactor Turbine and Control Buildings TRV

The reviews consisted of the DCR packages, including the 10 CFR 50.59 reviews, individual design drawings within the DCR packages and applicable design drawing notes. The observations included some of the installation of DCR 93-31. This included placement of piping, pumps, hangers, pump and motor alignments, and electrical cable installation and terminations. The inspectors were briefed by the design/modification engineer and discussed the planned performance test of the system. This test was scheduled to be performed on day 5 of the outage. The inspector will continue to followup on the post modification activities associated with this DCR.

The inspectors reviewed minor design change 94-5001 and observed work in progress. This work is being performed to correct degradation in the tornado vents. On the RB, the vents are part of the secondary containment boundary. The inspectors' review indicated that the installation of the new overlay panels on the RB roof vents was such that operability of the vents was not affected. Because activities were in progress on the refueling floor, the inspectors verified that the workers were being careful regarding inadvertent activation of a vent. As discussed in paragraph 2b of this report, the inspectors noted that the roof in the area of the seam between the two RBs needed repairs. Review of the evaluations and other supporting documentation did not identify any deficiencies. The design change will affect the pressure at which the panels will actuate under some circumstances. This change was fully supported and will be reflected in the next FSAR revision. Primarily because the operation of the relief vents involves passive devices, periodic testing of the relief vents is not performed. A potential concern would be that over the years, degradation of the equipment could occur and the vents may not actuate. However, the inspectors were informed that one of the vents on the turbine was actuated during the work activities and the vent operated as expected.

One of the inspectors periodically reviewed and observed a Unit 1 modification. DCR 89-281, Removal and Replacement of the Unit 1 Reactor Building Chiller Water System, installed four 200 ton train chillers and increased the chilling capacity by approximately 50%. Activities observed included cable pulling, cable terminations (various sizes and conductors), hanger installation, pump and motor placement, and post modification testing. The system was classified as non-safety related. However, it was a major modification and should address concerns involving high ambient temperatures in the Unit 1 reactor building. All activities observed were conducted with adequate supervision and engineering support.

No violations or deviations were identified.

8. ESF Walkdown (71710)

The inspector conducted a walkdown of the Unit 1 EDG system. Electrical board, starting air system, switch positions cooling water valves and battery charger line ups were verified in the control room and locally to ensure the lineups were in accordance with operability requirements. Walkdowns of the EDG spaces, switchgear and battery rooms were performed to verify equipment conditions, housekeeping and cleanliness. The review included deficiencies identified over the last two years and ongoing concerns. In preparation for the inspection the following documents were reviewed: applicable sections of the FSAR and TS, surveillance procedures, operating procedures, maintenance procedures, and recent SORs related to the EDG systems. Other procedures, including fuel oil day tank cleaning, starting air compressor maintenance, and fuel oil storage tank cleaning were also reviewed.

The inspector noted that the licensee had identified a significant concern involving the 1A and 1C EDGs. Information supplied by licensee representatives indicated that the end electrical windings of the two generators were starting to deform. The windings were originally equipped with spacers and several of the spaces have fallen out over the years. Among the recommendations made by engineering was to replace the spacers during the Fall 1994 outage, obtain a new stator with windings, replace the 1A and 1C EDG stators on a revolving schedule involving the spring 1996 outage and the Fall 1997 outage, and as an interim measure electrical megger the windings every three months. The inspectors reviewed the licensee's documentation which concluded that no immediate or short term operability concern existed. The inspector concluded that operability was adequately supported and the evaluations were appropriate.

The inspector periodically reviewed and observed the activities involved with EDG Fuel Oil Day Tank level indications. During the January to February time frame, continuing problems with level indications were experienced. The indicated levels in the 1A, 1B and 1C EDG fuel oil day tanks did not reflect the actual level. Licensee personnel investigated, repaired and/or calibrated four level indicators and three level transmitters. It was determined that the span of the level transmitters did not match the oil level in the tanks. The problem was solved when the transmitters were calibrated to new values based on the actual tank curvature. The inspector determined that no deficiencies involving operability or TS compliance were involved.

Based on the observations, walkdown, and reviews, the inspector concluded that the EDGs, related electrical distribution equipment, and EDG support systems, were being maintained properly to support TS and operations requirements.

No violations or deviations were identified.

9. Inspection of Open Items (92700) (92701) (90712)

The following items were reviewed using licensee reports, inspections, record reviews, and discussions with licensee personnel, as appropriate:

a. (Closed) LER 50-321/93-01: Unplanned Scram Due to Loss of Condenser Vacuum and Group 2 PCIS Actuation. This LER was issued to document a manual scram event which occurred on March 16, 1993. Details were documented in IR 50-321,366/93-05. Post trip review indicated that steam trap 1N22-D014, located in the three-inch condensate drain line from the in-service Unit 1 steam packing exhauster, had stuck in the open position. This allowed an excessive amount of air in-leakage, which caused the steady loss of condenser vacuum. The post trip review also indicated that Group 2 PCIS valve 1G11-F019, the inboard drywell equipment drain sump pump discharge isolation valve, did not close within the Unit 1 TS required time limit. The licensee repaired steam trap 1N22-0014 per MWO 1-91-7740 and valve 1G11-F019 per MWO 1-92-1784. Based on this review of the licensee's activities, this LER is closed.

b. (Closed) LER 50-366/93-02: "As-Found" ILRT Failure. An ILRT was performed on the Unit 2 primary containment on November 6-7, 1992. The results of the test indicated that the "as-left" leakage rate was found to be with TS limits. Subsequent to the ILRT the A/E complied the LLRT results and calculated that the "as-found" containment integrated leak rate was in excess of the TS limit. The licensee concluded that the majority of the excessive leak rate, 25%, was through penetration X-222B due to the leaks in the Recombiner System. Repairs were made to the system and successful leakage testing was performed. Based on the completed repairs and the performance of a successful leakage test this LER is closed.

c. (Closed) VIO 50-321,366/93-08-02: Failure to Perform TS Surveillance Testing of the 1B EDG. This violation addressed the ongoing difficulties with the performance of surveillance Testing. The concerns and observations were documented in IRs 50-321,366/93-08, 93-02 and 92-34. The inspector reviewed the licensee's response dated July 27, 1993. The licensee indicated that the failure to perform the test was due to personnel error. The surveillance tracking and scheduling coordinator, when changing the scheduling computer program data base entry, unintentionally caused the 1B diesel generator's monthly operability test to be rescheduled past the next due date. The inspector discussed this item with the coordinator and noted that no TS surveillance tests have been late since this occurrence. Based on this review, the violation is closed.

8. Exit Interview

The inspection scope and findings were summarized on March 11, 1994, with those persons indicated in paragraph 1 above. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection.

Item Number	Status	Description and Reference
50-366/94-05-01	Open	VIO - Failure to Identify Elevated HPCI Thrust Bearing Temperature, paragraph 2d.
50-366/94-05-02	Open	VIO - Failure to Follow HPCI Testing Procedure, paragraph 2d.
50-321/94-05-03	Open and Closed	NCV - Temporary Storage of New Fuel Procedural Issues, paragraph 6.

9. Acronyms and Abbreviations

A/E - Architect Engineer
CFR - Code of Federal Regulations
CR - Control Room
DC - Deficiency Card
DCR - Design Change Request
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
ERT - Event Review Team
ESF - Engineered Safety Feature
°F - Degrees Fahrenheit
FPM - Fission Process Monitor
FSAR - Final Safety Analysis Report
GE - General Electric Company
HP - Health Physics
HPCI - High Pressure Coolant Injection System
I&C - Instrumentation and Controls
IFI - Inspector Followup Item
ILRT - Integrated Leak Rate Test
IN - Information Notice
IR - Inspection Report

LCO - Limiting Condition for Operation
LER - Licensee Event Report
LLRT - Local Leakrate Test
MG - Motor Generator
MSIV - Main Steam Isolation Valve
MWO - Maintenance Work Order
NCV - Non-Cited Violation
NPRDS- Nuclear Plant Reliability Data System
NRC - Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation
NSAC - Nuclear Safety and Compliance
PCIS - Primary Containment Isolation System
PEO - Plant Equipment Operator
P&ID - Piping and Instrumentation Drawing
PMMS - Plant Modifications and Maintenance Support
PRB - Plant Review Board
PRC - Potential Reportable Concern
PSIG - Pounds Per Square Inch
PSW - Plant Service Water System
RB - Reactor Building
RCIC - Reactor Core Isolation Cooling System
RCS - Reactor Coolant System
RFP - Reactor Feed Pump
RFPT - Reactor Feed Pump Turbine
RG - Regulatory Guide
RHR - Residual Heat Removal
RHRSW- Residual Heat Removal Service Water System
RPS - Reactor Protection System
RTP - Rated Thermal Power
RWCU - Reactor Water Cleanup
RWP - Radiation Work Permit
RX - Reactor
SAER - Safety Audit and Engineering Review
SBGT - Standby Gas Treatment
SCS - Southern Company Services
SIL - Service Information Letter
SNC - Southern Nuclear Corporation
SOR - Significant Occurrence Report
SOS - Superintendent of Shift (Operations)
SPDS - Safety Parameter Display System
SRO - Senior Reactor Operator
SS - Shift Supervisor
STA - Shift Technical Advisor
TRV - Tornado Relief Vent
TS - Technical Specifications
URI - Unresolved Item
V - Volts