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

Report Nos.: 50-321/92-32 and 50-366/92-32

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: December 6, 1992 - January 9, 1993

Inspectors:	Scott E. Sparks for	2/4/93
	Leonard D. Wert, Jr., Sr. Resident Inspector	Date Signed
	Scott E. Sparks for	2/4/93
	Edward F. Christnot, Resident Inspector	Date Signed
Approved by:	Pierce H. Skinner	2/4/93
	Pierce H. Skinner, Chief, Project Section 3B Division of Reactor Projects	Date Signed

SUMMARY

Scope: This routine, announced inspection involved inspection onsite in the areas of: operations, including overflow of the reactor building sump; a drywell-to-torus vacuum breaker issue; a remedial emergency preparedness drill; surveillance testing, including a review of recent missed testing and an inadvertent Engineered Safety Feature (ESF) actuation; maintenance activities; ESF walkdown; and review of open items. Additionally, one of the inspectors visited the corporate offices during the period.

Results: Two non-cited violations (NCV) and two inspector followup items (IFI) were identified.

The first NCV involved the licensee's identification that a Standby Gas Treatment System (SBGT) surveillance had not been completed within the interval required by Technical Specifications (TS). It was discovered during the recent Unit 2 refueling outage that the testing had been missed during the previous outage (NCV 366/92-34-01: Missed SBGT 18 Month Surveillance Testing, paragraph 3a).

The second NCV addressed a personnel error which resulted in an inadvertent ESF actuation during testing. The ESF actuation occurred when a contract engineer went to the wrong control room

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panel and initiated a simulated logic signal. The Loss of Offsite Power/Loss of Coolant Accident (LOSP/LOCA) logic system was actuated and ECCS systems responded (NCV 366/92-34-04: ESF Actuation During LOSP/LOCA Diesel Generator Testing, paragraph 3c).

The first IFI addressed a recent number of examples of missed TS required surveillance tests. The examples were identified by the licensee. Due to an increase in the number of missed tests identified over the past several months, the inspectors reviewed records in this area. Licensee Event Reports (LER) and inspection reports were examined in detail. It was noted that the majority of the recent examples involved personnel error and/or communications problems. Additional review is needed in this area to ensure controls of the surveillance program are adequate to address the concern (IFI 321,366/92-34-02: Missed TS Surveillances, paragraph 3b).

The other IFI concerns onsite radio communications problems noted during the inspector's observation of a remedial fire drill. Several instances of problems involving inability to communicate with radios during actual or simulated fire conditions have been discussed in previous inspection reports. While alternate means of communications have been available and used in these instances, personnel expect the radios to be functional and rely on their use (IFI 321/92-34-03: Onsite Radio Communications Problems, paragraph 2d).

In addition to NCV 366/92-34-04, two other examples involving less than appropriate attention to detail were noted. An overflow of the Unit 1 reactor building sump occurred during a flushing evolution on a Residual Heat Removal Service Water System piping drain line (Paragraph 2b). Additionally, indications that a drywell-to-torus vacuum breaker had remained at least partially opened after a test were not acted upon promptly. The inspector's review concluded that the vacuum breaker had remained partially open or unseated for about 22 hours despite specific guidance in a TS clarification which directed the operators to monitor for such an occurrence. The licensee's actions after the indications were noted by a shift supervisor were appropriate (Paragraph 3c).

One of the inspectors visited the Southern Nuclear Operating Company offices in Birmingham, Alabama, to conduct inspection followup on several issues. It was concluded that the corporate organization's commitment to providing strong support of the Hatch site is continuing (Paragraph 6).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

J. Betsill, Unit 2 Operations Superintendent
*C. Coggin, Training and Emergency Preparedness Manager
*D. Davis, Plant Administration Manager
*P. Fornel, Maintenance Manager
O. Fraser, Safety Audit and Engineering Review Supervisor
*G. Goode, Engineering Support Manager
J. Hammonds, Regulatory Compliance Supervisor
*W. Kirkley, Health Physics and Chemistry Manager
J. Lewis, Operations Manager
*C. Moore, Assistant General Manager - Plant Support
*D. Read, Assistant General Manager - Plant Operations
*P. Roberts, Acting Outages and Planning Manager
*K. Robuck, Manager, Modifications and Maintenance Support
*H. Sumner, General Manager - Nuclear Plant
*J. Thompson, Nuclear Security Manager
*S. Tipps, Nuclear Safety and Compliance Manager
*P. Wells, Unit 1 Operations Superintendent

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

NRC Resident Inspectors

*L. Wert
*E. Christnot

* Attended exit interview

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

2. Plant Operations (71707)

a. Operational Status

Unit 1 operated at full rated power for the entire report period with the exception of several hours at about 80 percent power to isolate a feedwater heater for repairs on January 7.

Unit 2 operated at full power for most of the report period subsequent to returning to power on December 14, after repairs to hydrogen leaks on several main generator neutral bushings.

Both units reduced power to about 680 MWe for about 2 hours on December 24, due to significantly reduced system load demand.

The inspectors reviewed plant operations throughout the reporting period to verify conformance with regulatory requirements, Technical Specifications (TS), and administrative controls. Control room logs, shift turnover records, temporary modification logs, LCO logs and equipment clearance records were reviewed routinely. Discussions were conducted with plant operations, maintenance, chemistry, health physics, instrumentation and control (I&C), and nuclear safety and compliance (NSAC) personnel. The inspectors also continued to periodically monitor the ongoing SFP cleanup project.

Activities within the control rooms were monitored on an almost daily basis. 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 reactor protection system channels, availability of power sources, and operability of the Safety Parameter Display system were monitored. Control Room observations also included ECCS system lineups, containment integrity, reactor mode switch position, scram discharge volume valve positions, and rod movement controls. Numerous informal discussions were conducted with the operators and their supervisors. Some inspections were made during shift change in order to evaluate shift turnover performance. Actions observed were conducted as required by the licensee's administrative procedures. The complement of licensed personnel on each shift met or exceeded the requirements of TS.

The inspectors verified the alignment of major portions of the Unit 2 plant service water system. Valve positioning was checked to ensure service water flow would be available to the 2A EDG, the 2C and 2D RHR pumps, the HPCI room coolers, the RHR/CS room coolers, and the MCREC condensing units. Additionally, the service water pump suction portion of the intake structure, the service water strainer pit and the traveling water screen areas were also toured in detail.

Selected portions of the containment isolation lineup were reviewed to confirm that the lineup was correct. The review involved verification of proper valve positioning, verification that motor and air-operated valves were not mechanically blocked and that power was available (unless blocking or power removal was required), and inspection of piping upstream of the valves for leakage or leakage paths. Information was received by the inspectors which indicated that another licensee had discovered foam rubber seals and duct tape had been used to seal against in-leakage around the SBGT system filter train fans. Apparently, this arrangement could permit RB atmosphere to bypass the SBGT filters. The inspectors walked down the SBGT system train installation. The Hatch Unit 2 installation had the fans, filters

and absorbers located in an air tight housing, and the Unit 1 installation had axial fans installed in the duct work with the filters and absorbers in an air tight housing. The inspector noted that both units had several conduits attached to their train housings and also to the Unit 1 fan motor. Additionally the inspectors verified that the drain lines on the filter train did not represent a path for bypassing the filters. The inspectors discussed these observations with the licensee's engineering personnel.

The inspectors closely reviewed the safety evaluation and implementation of TMM 2-92-153. This modification de-energized the solenoids on the air supply lines to valves 2P41-F035 A/B, 2P41-F036 A/B, 2P41-F039A/B, and 2P41-F040A/B. A similar modification was implemented on Unit 1. The modification positions or fails the valves to the open position and results in continual PSW flow through the ECCS room coolers (normally the valves open on fan actuation as a result of an ECCS signal or temperature requirements). This TMM was implemented in response to increased failures of the ASCO model NP206 solenoid valves. The failure of these valves is addressed in LER 321/92-03 and Inspection Report 321,366/92-12. Recently, several valves had stuck closed during the weekly testing utilized as an interim corrective action by the licensee. The inspector noted that Bechtel had reviewed the modification and concluded that the other components supplied by PSW (under nonaccident conditions) would not be adversely affected. The potential for erosion due to the service water flow was also reviewed. The inspectors toured the ECCS rooms and verified that no excessive condensation was occurring as a result of the constant flow of the cool (about 50 degrees F.) PSW through the coolers. The inspector concluded that the evaluation addressed the potential concerns adequately and the method of implementation of the modification was appropriate. The licensee is continuing to pursue a permanent resolution to the solenoid valve problem.

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

Reactor Buildings
Station Yard Zone within the Protected Area
Turbine Building
Intake Building
Diesel Generator Building
Fire Pump Building
Central and Secondary Alarm Stations

During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed. No significant problems were noted. Paragraph 5 discusses a detailed walkdown of the Unit 2 HPCI system during which only very minor discrepancies were noted. Paragraph 3b of

this report discusses some observations made during an inspection of the SBGT filter trains.

b. Overflow of the Unit 1 Reactor Building Sump

On December 21, 1992, during performance of a RHRSW pump operability test, an excessive amount of water was flushed into the drain system for the Unit 1 RB east corner rooms and the HCPI room. This resulted in water (containing significant quantities of dirt from the drain system) backing up into the east corner rooms and HCPI room. The resulting residue covered the floor area of all three rooms and the water level appeared to have reached approximately 1 to 1.5 inches deep. The licensee promptly cleaned up the floors of the rooms and commenced decontamination activities on the same day. The inspectors discussed the issue with licensee personnel and toured the involved areas to verify that no safety systems were adversely affected. The inspectors observed clear indications of sump overflow by the flow patterns in the residue on top of the sump enclosure.

The inspectors examined the area where the various valves were manipulated to accomplish the flush and reviewed the applicable procedure. Procedure 34SV-E11-004-1S: RHRSW Pump Operability, contains steps to utilize RHRSW pump discharge pressure to flush a section of piping intended to drain the RHR/RHRSW cross connection piping. In the past, the drain line has become blocked by silt and mud and some slight contamination of the RHRSW piping had been detected. The procedure provided a series of valve manipulation steps to accomplish the activity. The inspectors noted that the sequence provided for opening and closing the various valves could result in an inadequate flush. The inspector also discussed with licensee personnel the cause of the excessive amount of water in the drain system. The procedure required that a 4 inch valve be opened and then closed as part of the flush. It was concluded that this valve had been in the open position for a longer than expected amount of time despite direction in step 7.3.2.20 of the procedure to "open and then shut" the valve. This resulted in the overflow of the sump. The inspectors confirmed that the specific cautions in the procedure to have the radioactive waste system operators monitor the sump levels during the evolution were complied with. The inspectors tours and the maintenance department's checks of several potentially wetted motors concluded that no safety systems were adversely effected. However, if the overflow had been more severe, a potential for adverse impact on safety systems would have existed. The licensee revised the procedure prior to the end of the report period and the flushing evolution was successfully performed.

c. Unit 2 Drywell-to-Torus Vacuum Breaker Issues.

During this period a problem was identified involving one of the drywell-to-torus vacuum breakers. On December 14, 1992, at

approximately 10:15 a.m., monthly testing of the vacuum breakers in accordance with 34SV-T48-002-2S: Suppression Chamber to Drywell Vacuum Breaker System Operability, was completed satisfactorily. Since this test cycles the vacuum breakers open and shut, at the end of the test the differential pressure between the drywell and the torus is zero. Under normal operating conditions, the drywell-to-torus differential pressure should (if all vacuum breakers are shut and not leaking and containment is intact) slowly increase as the drywell pressure increases. Approximately 22 hours after the testing was completed, it was noted that the differential pressure (d/p) was still at zero. These conditions would be seen if a vacuum breaker remained partially open after the test. Vacuum breaker 2T48-F323D had not reseated under similar circumstances in June, 1992, after a hydrogen recombiner test had reduced the d/p to zero. In that case, the operators had identified the problem by noting the failure of the d/p to increase slowly after the test had been completed. Inspection Report 321,366/92-15 contains a discussion of that instance.

Periodic venting (about once each shift) of the drywell is normally required due to a small amount of nitrogen leakage into the drywell. After the 2T48-F323D occurrence, TS clarification 0-92-02 was issued by NSAC. It addressed the observed d/p indications and the specific wording of TS 3.6.4.1 which requires the vacuum breakers to be "operable and closed". The clarification stated that if a zero d/p exists during normal steady state conditions then a vacuum breaker is probably partially open and the TS actions for an open vacuum breaker need to be followed even if the indications show the vacuum breaker fully closed. The clarification also states that after a surveillance is performed which could affect the d/p, the re-establishment of a d/p should be confirmed.

At about 8:15 a.m. on December 15, 1992, CR personnel noted that one of the "shut" indications on vacuum breaker 2T48-F323G was not lit. Upon further investigation, it was noted that the drywell-to-torus differential pressure still indicated a zero value. Suspecting that the vacuum breaker was not fully seated, the SS directed that a positive d/p be established by the operators to seat the breaker. At 8:40 a.m., a d/p of 0.3 psid was established by operation of the Drywell-to-Torus d/p system, and all of the 2T48-F323G indications showed the breaker was shut. After this was done, the d/p initially appeared to behave as expected under typical plant conditions. At 1:05 p.m., LCO 2-92-1013 was written to document the 2T48-F323G problem. The LCO was entered at 8:15 a.m. and was exited at 8:40 a.m. when the vacuum breaker was "reseated". At 6:00 p.m., LCO 2-92-1014 was initiated on 2T48-F323G at the direction of management. The requirements of TS action statement 3.6.4.1.d (completion of testing in accordance with TS 4.6.4.1.a and 4.6.4.1.b) were completed at 7:40 p.m. The actions included cycling the operable vacuum breakers in accordance with 34SV-T48-002-2S and performance of a drywell-to-

torus leakage test in accordance with 34SV-T48-004-2S. After this testing, it was noted that if the drywell-to-torus d/p was allowed to go below about 0.35 psid, the d/p would then slowly decrease to zero rather than slowly increase. This indicated that the 2T48-F323G vacuum breaker was not seating fully closed whenever less than 0.35 psid existed between the drywell and the torus.

The inspectors became aware of the problem early on December 16 and monitored the licensee's actions and the d/p indications. The licensee continued to consider 2T48-F323G as inoperable through December 17. The inspectors discussed the issue with regional management and NRR personnel. On December 17, 1992, a telephone conference involving the licensee and the NRC was held. The major question involved TS 3.6.4.1 which requires the vacuum breakers to be "operable and closed" and whether a "closed" but "leaking" vacuum breaker required entry into the action statements. It was concluded that the licensee's determination that the 2T48-F323G vacuum was operable was acceptable. The primary reasoning was that the vacuum breakers are required to perform two actions to accomplish their intended safety function. The breaker must open when torus pressure is a value less than or equal to 0.5 psid greater than drywell pressure. The vacuum breaker must also shut in the event of a LOCA to ensure that the suppression function of the torus is not bypassed. The testing performed on 2T48-F323G indicated that these functions would be fulfilled. The inspectors noted that the TS bases state that the vacuum breakers "must not be inoperable in the open position". This provides additional support of the interpretation.

On December 17, 1992, Operating Order 00-07-1192S was issued which listed specific operator actions required to address the problem with 2T48-F323G. Included were requirements to monitor d/p every 4 hours (previously required only once each shift) and maintain it above 0.35 psid. In the event that the pressure decreases below 0.35 psid, action is required to increase the d/p such that the vacuum breaker will be fully seated. A TS clarification was issued which more specifically addressed actions to be completed in the event of a "leaking" vacuum breaker.

The inspectors identified a concern during their review of the issue. The abnormal behavior of the drywell-to-torus d/p was not identified by CR personnel for approximately 22 hours after the vacuum breaker testing had been completed despite information in the TS clarification which specifically cautioned against such an event. In addition to monitoring of the d/p expected during routine evolutions, the d/p is recorded every 12 hours in the logs required by 34SV-SUV-2S.

The inspectors concluded that the problem with the longterm zero d/p (not increasing as expected) was not identified in a timely manner. The failure to identify the abnormal differential

pressure indications is considered a weakness in attention to detail on the part of CR watchstanders.

d. Emergency Preparedness Drill

On December 14, 1992, an emergency preparedness drill was conducted by the licensee. The inspectors focused on observation of the two remedial aspects of the drill and also attended the post drill critique.

Inspection Report 321,366/92-19 contained a discussion of an exercise weakness involving the fire brigade performance, fire scene controller performance, and fire brigade communications during an evaluated exercise. The report stated that a remedial drill would be conducted for observation by the resident inspectors. Inspection Report 321,366/92-15 contained discussion of the inspector's review of a radio communications problem which occurred during response to a small fire in the plant on June 11,1992. Inspection Report 321,366/92-17 stated that the licensee would conduct a drill which would include utilization of the alternate EOF prior to the end of 1992. That facility had never been tested by a drill.

One of the inspectors visited the alternate EOF (located in the GPC operating building in Baxley) during the drill shortly after it had been manned. The inspector noted that communications equipment was functioning and that security had been established at the facility. The dose assessment computer had been moved from the Hatch site EOF to the alternate EOF and was operational. During part of the drill, the dose assessment function was controlled from the alternate EOF. The inspector concluded that the alternate EOF contained adequate space and the necessary equipment to fulfill its function if it were needed. The movement of personnel and some equipment between the two facilities appeared to go smoothly. The inspectors noted that the licensee has requested to change the location of the alternate EOF to the FEOC building in Vidalia.

During observation of the fire brigade portion of the drill (a fire was simulated in a SUT), radio communications problems were noted. The fire brigade leader was unable to contact the simulator CR or the main CR on his radio. After several minutes of unsuccessful communication attempts, the leader sent an individual to a nearby phone for communications. The inspectors observed that 4 members of the fire brigade responded to the scene of the fire within 3 minutes of the fire being announced. The inspectors noted that the time interval from initial notification of the fire to water being applied (simulated) was about 20 minutes. After the fire was extinguished, damage assessment appeared to be prompt and appropriate in scope. The inspectors noted the controllers used large photographs of a transformer fire to provide information to the fire brigade members. This was an

effective simulation technique. The radio communications were the only area in which significant problems were noted which had been identified in the earlier drills. After the drill, some investigation was conducted into the problems. A problem in the "receive" circuitry of the main CR fire radio monitor was identified. Additionally it was noted that the batteries for the radios utilized by the operations fire brigade are maintained in a charged state by use of a "timer" type of charger instead of a continuous charge/periodic discharge arrangement. The licensee is continuing efforts to resolve the problem. Since several prior instances of problems involving radio communications have been noted, the inspectors concluded that additional actions should be considered by the licensee. The inspectors observed that significant reliance is placed on use of the radios during drills and events. IFI 321/92-34-03: Resolution of Onsite Radio Communications Problems, will be used to follow this issue.

One IFI and two examples of lack of appropriate attention to detail were identified.

3. Surveillance Testing (61726) (61701)

a. 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. 57SV-T47-002-2S: Primary Containment Temperature Instruments Channel Calibration

   2. 34SV-E51-002-2S: RCIC Pump Operability

   3. 57SV-C11-001-2S: High Scram Discharge Volume Level Instrument FT & C

   4. 34SV-E41-002-2S: HPCI Pump Operability

   5. 42SV-T46-003-1S: Testing of SBGT Filter Trains

   During observation of the HPCI testing on December 21, 1992, the inspector noted that a snubber strut (2E41HPCIR78B) on the steam supply line appeared to be bent. The PEO involved in the test

initiated DC 2-92-4618 to address the concern. At approximately 4:15 p.m., on December 23, a 72 hour LCO was initiated. The snubber was replaced early on December 24. Subsequent testing of the snubber indicated that the snubber had not been locked up and it was fully operable. The inspectors noted during a review of the MWO history of the snubber that MWO 2-92-5007 had been initiated on September 28, 1992, to address the same bent strut. That MWO had specifically stated that the snubber was not inoperable. The cause of the bent strut is being reviewed by the licensee.

The inspector noted that an appreciable amount of smoke accumulated in the HPCI room during the approximate 30 minute test run. This was noted by the PEOs involved in the test and apparently was caused by oil or other residue on the hot system piping. A DC was initiated to fully review this issue.

The inspector also noted that step 7.2.29 of 34SV-E41-002-2S requires an inspection of the HPCI discharge piping supports in the HPCI room at the end of the testing. The PEOs were aware of the procedure step and completed an overall look at the discharge piping within the HPCI room. The arrangement of the piping does not facilitate a detailed examination of the supports. Only a gross failure of a snubber component would be readily detected by this check. The inspectors walked down the discharge piping in the torus area as discussed in paragraph 5 of this report.

The inspector reviewed and observed the Unit 1 train A SBGT system ventilation performance, integrity, dioctyl phthalated (DOP), and halogenated hydrocarbon surveillance test. The performance of this surveillance is required by TS once per operating cycle, not to exceed 18 months or after every 720 hours of operation. The testing activities were controlled by procedure 42SV-T46-003-1S: Testing of SBGT Filters Trains. The inspector reviewed the procedure prior to the performance, observed the testing activities in progress and reviewed the results. The test required vendor participation and was performed under the system engineers supervision over a two day period of time. The test results were acceptable.

In recent months, several LERs addressing examples of missed TS surveillances have been submitted. LER 366/92-22 addressed missed functional testing of several ATTS trip units. LER 366/92-24 involved missed portions of a TS surveillance on the SBGT system. The testing was required to be performed every 18 months and had been due May 19, 1991. The missed portions were completed satisfactorily on November 17, 1992, after an engineer discovered the problem. LER 366/92-25 addressed missed functional testing of HPCI and RCIC ATTS trip units. It was noted that personnel error and/or poor communications had played major roles in these tests not being performed as required.

The missed SBGT system testing is of particular concern since the 18 month periodic surveillances are relied upon to identify system operability issues. The test had been properly scheduled for completion near the conclusion of the refueling outage and the procedure (34SV-T46-001-0S: SBGT Operability) had been initiated. However, only portions of the procedure were completed. The steps required for the weekly (during outages) testing of secondary containment were completed, the remaining sections required to be completed for the 18 month TS requirements were not performed. The surveillance task sheet was incorrectly returned to the surveillance coordinator marked "full completion." The error was identified by the SBGT system engineer when he reviewed the surveillance records during the recent outage testing of the SBGT system.

The inspectors reviewed this issue in detail to assess the safety significance. The testing which was omitted was required by TS 4.6.6.1.1.d. This testing involves measurement of the heater energy output and the differential pressure across the SBGT filters. The testing was completed satisfactorily on November 17. The LER stated that no work had been performed in the interim period which would have effected the ability of the heaters to perform their function. The inspectors did not identify any records of work that had been performed on the heaters. The LER also stated that the SBGT filter differential pressure is monitored and abnormally high differential pressure would be annunciated in the CR. The inspectors closely reviewed this area. While reviewing the SBGT train installation the inspector reviewed the applicable Unit 2 TS and the Unit 2 alarm response procedures. The specific TS section reviewed was 4.6.6.1.1.d.1 which stated that at least once every 18 months the pressure drop across the combined HEPA filters and charcoal absorber banks is to be verified as being less than 6 inches WG with a flow rate of approximate 4000 cfm. The alarm response procedure stated that the alarm for the pressure drop across the prefilter, the two HEPA filters, and the charcoal filter was set to alarm at 9 inches WG. The alarm procedure also stated that if SBGT system operation was required after the alarm, operation could continue until the differential pressure across the pre-filter was equal to, or less than 4 inches WG as read on the local indicator (2T46-R011 A/B), mounted on the SBGT system train housing, or until the differential press across the HEPA filters was equal to or less then 8 inches WG as read by their locally mounted indicators (2T46-R012 A/B or 2T46-R014A). The inspector noted during the installation walkdown that these locally mounted indicators did not correspond to the alarm response procedure. Indicators 2T46-R011 A/B would be pegged out at 2 inches WG yet the procedure called for 4 inches WG. Indicators 2T46-R012 A/B and 2T46-R014 A/B would be pegged out at 4 inches WG yet the procedure called for 8 inches WG. The locally mounted indicators 2T46-R013 A/B monitored the differential pressure across the charcoal absorbers and pegged out at 8 inches WG. These discrepancies were discussed

with the licensee and the inspectors will follow the corrective actions.

The failure to perform the surveillance testing is a violation of TS 4.6.1.1.d. This violation will not be subject to enforcement action, because the licensee's efforts in correcting the violation meet the criteria specified in section VII.B of the Enforcement Policy. This issue is identified as NCV 366/92-34-01: Missed SBGT 18 Month Surveillance Testing.

b. Missed TS Surveillances

Due to the recent reports of missed TS surveillances, the inspectors conducted a review of all surveillance testing problems identified over the past several years. All LERs and inspection reports in the last two years were reviewed. The following significant observations or conclusions were noted:

- Inspection Report 321,366/91-11 contains the results of a detailed review of the 12 1990 LERs which involved missed surveillances. Of these, 10 were caused by less than adequate procedures. The licensee's Commitment Tracking Verification Program had identified about 50 percent of the problems.

- In 1991, 8 LERs were submitted which addressed missed surveillance tests. Of these, 2 were identified by a licensee task force set up to review chemistry department surveillance procedures and 1 was identified through the licensee's detailed review of the MCREC system. Most of the LERs attributed the deficiencies to less than adequate procedures in that the procedures did not contain the appropriate required testing or interval. The inspector's review of the LERs indicated that only one of the issues involved an easily preventable personnel error. An incorrectly performed editorial correction had resulted in a daily check of the torus oxygen content being missed.

- The SALP report for the period ending on May 31, 1992, noted that fewer problems had resulted (compared to the previous SALP) due to noncompliance with surveillance procedures. The report also noted that many of the missed surveillances were identified through the licensee's self assessment efforts.

- In 1992, 10 LERs involving missed surveillance tests were submitted. Of these, one was identified as a result of the licensee's followup of a previous similar example and another was identified by NSAC during review of an inadvertent ESF actuation. None of the issues were identified through a programmatic review of surveillance testing. The majority of the issues were attributed to personnel error. The inspectors noted that poor communications played a direct role in at least 2 of the events. Only one of the LERs was attributed to procedural problems and

that example was the one identified by NSAC. Several were caused by incomplete performance of testing procedures.

- A review of inspection reports issued in the last two years indicated that at least six non-cited violations and two violations have been identified involving missed TS surveillances.

Many of the above LERs were addressed in previous inspection reports and were individually assessed. The inspectors concluded that the fact that so many of the recent missed tests involved personnel error is a concern. In LER 366/92-25 the licensee's planned corrective actions included a review of all ATTS testing and an overall review of the recent similar missed TS surveillance tests. One of the inspectors attended the first meeting of a task force established to review the issue. The inspectors will continue to follow the licensee's actions on this issue.

The inspectors concluded that additional review should be conducted of the overall surveillance program and the licensee's actions in response to the recently identified series of missed tests. IFI 321,366/92-34-02: Missed TS Surveillances, will be used to follow this issue.

c. Inadvertent ESF Actuation Due to Personnel Error During Testing.

The inspectors reviewed the events involving an unplanned ESF actuation on Unit 2 which occurred at 5:23 a.m., EST, on November 14, 1992. Unit 2 was in cold shutdown with various refueling outage activities in progress. A surveillance logic functional procedure, 42SV-R43-016-2S: Diesel Generator 2C LOCA/LOSP LSFT, was in progress. The procedure provided instructions for defeating some of the logic so that the EDGs, ECCS pumps, and ECCS valves would not actuate during the performance of the test. The logic defeating work included the use of purple colored temporary modification tags for lifting leads and installing jumpers. Control Room Panel 2H11-P627 contained the majority of the tags and houses the DIV II ECCS logic. DIV I logic is located in panel 2H11-P626. After the completion of the work in panel 2H11-P627, the employee left the control room to perform additional pre-test lineup activities. After returning to the control room, the employee erroneously proceeded to panel 2H11-P626 and, failing to notice the absence of tags, he installed two jumpers to simulate a low water level signal into the DIV I logic instead of the DIV II logic as required by the procedure. EDGs 2A, 2C and 1B auto started, Core Spray Pumps 2A and 2B started, RHR pumps 2A and 2D started, injection valves for the DIV I core spray and RHR opened, control room ventilation shifted modes, and the PSW to turbine building valves closed. This resulted in water being injected into the reactor vessel from the "A" core spray and RHR system pumps. The operators secured the pumps 18 seconds after the event and the water level in the vessel increased approximately 34 inches. The inspector concluded that the event was caused by

personnel error involving attention to detail. This violation will not be subject to enforcement action, because the licensee's efforts in correcting the violation meet the criteria specified in section VII.B of the Enforcement Policy. This item is identified as NCV 366/92-34-04: ESF Actuation During LOSP/LOCA Diesel Generator Testing.

One IFI and two NCVs were identified.

4. Maintenance Activities (62703)

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, cleanliness, and 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 2-92-3243: RPS MG (2C71-S001B) Circuit Breaker

2. MWO 2-92-4416: RPS MG Set 5 Year PM

3. MWO 2-92-4417: RPS MG Set 1 Year PM

The inspector reviewed and observed the performance of the five year PM on the Unit 2 B RPS MG set (2C71-S001B). Procedure 52PM-C71-001-0S, RPS MG Set System Maintenance, was used to control the activities. The inspector noted that both the one year and the five year PM was performed. The inspector specifically observed the removal of the generator stator, the cleaning and inspection of the motor stator and rotor, the post installation meggaring of the motor and the sign off of completed work.

No violations or deviations were identified.

5. ESF Walkdown (71710)

The inspectors conducted a walkdown of the Unit 2 HPCI system. The Unit 2 FSAR, TS and SED were reviewed in preparation for the inspection. The walkdown included verification that the system lineup requirements in procedure 34SO-E41-0-01-2S: HPCI System, were equivalent to the configuration delineated in P&IDs H-26020 and H-26021. The detailed walkdown included verification that valves, breakers, and switches were properly positioned.

During the inspection, various piping supports and hangers were examined. During verification of portions of the system located outside

the RB, (CST enclosure area) the inspectors noted indications that the freeze protection heaters were operating properly. Emphasis was placed on verification of proper instrumentation valve alignment and ensuring indicated parameters were as expected. Portions of supporting systems were also walked down in detail. PSW alignment was verified from the intake structure to the room coolers.

No significant discrepancies were identified. General house keeping conditions and cleanliness were adequate with only a few pieces of small debris noted. A small puddle from a minor packing leak on a steam line drain valve was reported to health physics personnel and corrective actions was initiated. Close observation indicated no excessive leaks in the control oil system even during testing of the system. Labeling of valves, breakers and major components was appropriate. As discussed in Paragraph 3 of this report, the inspectors noted that only those portions of the discharge piping located in the HPCI room were reviewed for water hammer indication. The inspectors walked down the HPCI discharge piping from the HPCI pump to near the junction point with the feedwater lines outside the HPCI room. No indications of water hammer or support problems were identified. The inspectors noted that temperatures on the discharge piping indicated that the discharge isolation valve (2E41-F006) was not leaking by its seat as it has on previous occasions.

No violations or deviations were identified.

6. Corporate Engineering and Technical Support Visit (40703) (37700) (92701) (92700)

During this report period the inspector visited the SNC offices in Birmingham, Alabama. The primary objective was to review additional information involved with LERs 321/92-13 and 366/92-13, the results of the Unit 2 ILRT due to the increasing leakage trend, the status of the IPE, the indications of jar cracking on the Unit 1 station battery, and the drawing problems identified while implementing a modification to the SRV control circuitry during the recent Unit 2 outage. The inspector attended meetings and discussed various HNP items with supervisors and managers.

The SNC personnel provided additional information concerning LER 321/92-13: Single Failure Vulnerability Discovered in the Intake Structure Ventilation. Inspection Reports 321,366/92-12 and 92-22 contain discussions of the inspectors' review of this issue. It was noted that the long term corrective actions involving modifications to the ventilation control system are scheduled for implementation in March, 1993. This item will be further reviewed when the modifications are completed.

The inspector also reviewed information received from licensee personnel concerning LER 366/92-13, Single Failure Vulnerability Discovered in a BOP System. On July 22, 1992, corporate support personnel identified a single failure in a BOP switchgear which could result in transient

conditions beyond those assumed in the licensing analysis. The failure involved the loss of power to BOP 120/208 volt AC distribution panel 2R25 - S023. This would de-energize the feedwater heater control circuitry and initiate a rapid feedwater temperature transient of 290 degrees F. The existing GE analysis for the loss of feedwater heating transient had assumed a temperature transient of 100 degrees F. Information reviewed by the inspector indicated that an analysis performed for this event indicated that the local power level in the limiting fuel node could have exceeded the mechanical over power, one percent plastic strain, and the thermal over power, fuel center line temperature, fuel design parameters. Additional information indicated that the safety limit in TS 2.1.2 (minimum critical power ratio), would not have been exceeded. The inspector noted that as part of the correction action a modification was prepared and was implemented during the recent Unit 2 outage. The inspectors discussed the safety significance and reportability of the issue with regional inspectors familiar with regulatory requirements in this area. Although the problem was identified and corrected by the licensee, the inspectors had a concern. The plant had been operated in a condition such that had the failure of one piece of nonsafety equipment occurred, the resulting consequences had not been fully analyzed. Additional review of the significance of the problem is ongoing.

The inspector noted that during the recent Unit 2 outage a design drawing discrepancy was discovered involving the SRV's and their setpoints. This discrepancy was between the mechanical setpoint and the new electrical setpoint for Unit 2 SRVs 2B21-F013 C and D. The new electrical setpoints had been installed by the implementation of DCR 91-134. The inspector reviewed an ERT report which indicated that a previously installed design change (DCR 81-139), implemented in 1984, was not closed out adequately. The site procedures were not revised to reflect the implementation of this DCR and the reason for this was unclear. When DCR 81-139 was initiated, the NSSS vender swapped the setpoints for SRVs 2B21-F013 C and D. The site procedure HNP-2-6020 was not revised to incorporate this change. This resulted in SRVs 2B21-F013 C and D having mechanical and electrical setpoints different from the setpoint index. An analysis was performed which indicated that with either a mechanical setpoint of 1090 psig or an electrical setpoint of 1100 psig, the 10 psig difference would be acceptable and operation through fuel cycle 11 with this difference was justifiable. The inspectors will conduct additional reviews in this area during the next refueling outage.

The inspector discussed the IPE results, the maintenance support group's personnel assignments and schedule, and the engineering support group's personnel assignments. Discussions were held with the HNP senior executive and various members of his staff.

No violations or deviations were identified.

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

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

a. (Closed) LER 366/90-01, Revision 1: Component Failure and Inadequate Design Cause Group I Isolation and Scram. This LER addressed a scram which occurred when a common sensing line valve failure resulted in a false low condenser vacuum signal in both trip systems of the MSIV isolation logic. The valve was repaired. The Unit 2 condenser vacuum sensing line tubing was reconfigured by implementation of DCR 2H90-003.

During the transient after the scram, HCPI injection valve (2E41-F006) shut on reactor high level when level was initially restored and could not be re-opened during subsequent operator attempts to start HPCI. RCIC and the CRD pumps were successful in controlling water level and no additional problems occurred during the transient. The inoperability of HPCI during a reactor scram transient resulted in this event being characterized as an accident sequence precursor with a 6.0E-5 conditional core damage probability by AEOD as discussed in NUREG/CR 4674.

The failure of 2E41-F006 was investigated in detail by the licensee. Revision 1 to LER 366/90-001 was issued on June 8, 1990 and included additional information in regards to the valve failure. An engineering investigation on the failure was completed by SCS. Evaluations of the motor, valve, and operator history were conducted. Twenty-four thermal overload heater elements of the type used in 2E41-F006 were current tested by Wyle laboratories. A review was performed of past TOL failures at Hatch. Additionally, SCS performed a review of NPRDS data to evaluate TOL relay heater elements failures throughout the industry. The inspector reviewed the reports of these analyses, discussed aspects of the issue with regional inspectors familiar with MOV requirements, and conducted some followup inspection regarding the valve.

The licensee concluded the cause of 2E41-F006 failing to open was an isolated component failure of the heater element for the TOL in the local breaker for the valve motor. The output contact of the relay is jumpered out to assure the valve will function in accordance with Regulatory Guide 1.106, but the heater element is physically part of the circuit supplying power to the motor of the valve. An open circuit in the element interrupts all power to the valve operator. Both heater elements in the starter (2R27-S093) were damaged. One of the elements used to provide an overload condition alarm, was distended and had some visible damage, but did not open circuit.

The heater elements were GE standard trip type with a 40 amp maximum continuous full-load capacity. The valve motor is rated

for 40 full-load amps and 815.9 locked-rotor amps. The inspector questioned if the heater elements had been sized in accordance with IEEE 741-1990, would this have resulted in larger sized elements and perhaps prevented the failure. The licensee responded that the elements had been sized properly with prior design practices (manufacturer's tables) and even if sizing by IEEE 741-1990 resulted in a larger capacity element, the element or another circuit component probably would have failed. It is expected that this area will be closely reviewed during future inspections of the licensee's MOV program.

The Wyle Lab testing indicated that the elements could withstand 200 percent overload for 15 minutes with no damage and were not subject to cracking or splitting until 700 percent overcurrent was applied. When overcurrents were supplied to the elements for 15 second periods, open circuits occurred at values of 300 to 400 amps. The elements began to glow red at 250-260 amps. The current vs time traces for 2E41-F006 indicated that the initial current on the valve opening stroke is about 250 amps and lasts less than a second. After the valve is unseated, current decreases to normal amps. If the valve stuck on its seat at least 250 amps would flow through the circuitry as long as the switch was held in the open position. The inspector noted documentation indicated that the control switch was held in the open position for about 30 seconds during 2 attempts to reopen the valve and even longer on the third attempt.

The inspector concluded that it was highly probable that a problem in the valve or the operator caused the valve not to open for undetermined reasons, and the sustained high currents during the repeated opening attempts resulted in the failure of the heater element. At least one past problem (September 1987) has occurred involving this valve sticking. The inspector noted that the licensee had reviewed the possibility of thermal binding and other binding problems but ruled those causes out. The inspector also noted that the valve frequently has developed seat leakage during operation. One possible cause would be that the seat leakage had been maintaining the valve hot and after the valve had shut following the cool HPCI flow through it, differential contraction or expansion rates of the valve components or the water in the valve had caused the valve to bind. The seat damage noted during the outage also supports that theory. This potential cause was discussed with the licensee. One concern would be that since seat leakage through the valve has occurred in the past, the event could occur again. The inspectors noted that the valve is not cycled after plant startup. The inspectors verified that there currently is not significant leakage by the valve.

The SCS review of industry wide failure of TOL relay heater elements concluded that most such failures were usually the result of undersizing of the elements or overcurrent conditions caused by other problems. The inspector noted that SCS had recommended that

an examination of TOL heater elements be conducted after any prolonged motor overload or overcurrent condition and in conjunction with any routine maintenance activities in which the MOV breaker enclosure is opened up. The inspectors could not locate any procedure requirements for such inspections. Maintenance management stated that these recommendations had not been incorporated into any maintenance procedures, but the elements would likely be inspected in the normal resolution of an overcurrent condition.

The inspectors reviewed the maintenance history of 2E41-F006 since the January 1991 repair activities. In April 1992, DC 2-92-1038 reported that the valve had a small seat leak. During the recently completed refueling outage the valve seats were lapped, the wedge was repaired, and the valve was repacked. DCR 91-052 was completed which upgraded the cabling (large size) from MCC 2R24-S022 to the operator. This should increase the voltage provided to the operator. Complete static VOTES testing was performed on the valve. The inspectors reviewed and discussed some of the results of the testing with an onsite valve testing engineer. The information indicated that the valve is set up in accordance with the design requirements and is operating properly.

The inspectors concluded that although the root cause of the heater element failure was not conclusively identified, extensive repairs and testing have been conducted in efforts to determine the cause and to ensure the valve continues to operate properly. In addition to testing of the valve, all required surveillance testing of the HPCI system has been performed without any additional 2E41-F006 problems. The inspectors will continue their followup on the thermal binding possibility discussed above. Based on this review, LER 366/90-01 is closed.

b. (Closed) IFI 321,366/91-04-03: SRVs Not Lifting at TS Setpoints. This item addressed a long-standing SRV setpoint drift problem. The setpoint drift is apparently caused by corrosion induced oxide bonding in the pilot valve portion of the 2-stage Target Rock Safety valves. The problem results in the SRVs not lifting within the TS limits. NRR personnel have agreed with licensees that the problem is not an operational safety issue since the valves performed within analyzed limits. In February 1991, both Hatch units experienced post-scram transients in which the valves did not lift within TS setpoints. Hatch management has continued pursuit of a resolution of this problem. Along with participation in the BWROG effort, a modification was developed which added pressure sensor electrical actuation of the valves. Electrical signals will actuate the SRVs at their mechanical setpoints. The modification was reviewed by the NRC staff. On July 24, 1992, the NRC safety evaluation approving the modification was issued. DCR 2H91-134 was completed during the most recent Unit 2 refueling outage and implemented the modification. The inspectors observed portions of the installation and testing. Some problems were

noted involving the drawings utilized for implementation of the modification. Paragraph 6 of this report discusses those problems. DCR 1H91-135 (the identical modification to the Unit 2 SRVs.) is scheduled for implementation during the spring 1993 Unit 1 refueling outage. Based on this review and the implementation of the SRV modification, this item is closed.

c. (Closed) LER 366/91-09: SRVs Experience Setpoint Drift Due to corrosion Induced Bonding. This LER addressed the licensee's identification that four of the eleven Unit 2 SRVs had experienced setpoint drift in excess of the TS allowed limits. Based on the review discussed above of IFI 321,366/91-04-03, and implementation of a modification to electrically actuate the Unit 2 SRVs at their mechanical setpoints, this item is closed

d. (Closed) IFI 321,366/91-20-02: Degraded Grid Protection Issues. This item was opened for followup of several concerns identified during the EDSFI. Details of the concerns are discussed in Inspection Report 321,366/91-202. The licensee initiated several actions to address the concerns including development of an operating order and modification of the 4160V ESF bus alarm circuitry. The Operating Order is discussed in Inspection Report 321,366/91-04. The inspectors verified during this report period that it is still active and present in the CR. A series of meetings has been held which included NRC, SNC, and GPC personnel. The major issue involves the licensee's reliance on administrative procedural controls to maintain the Hatch 230 KV switchyard voltage above 101.3 percent. Item a of Violation 91-202 involved this issue and was denied by the licensee. As discussed in Inspection Report 321,366/91-202, this value of switchyard voltage is required to ensure all safety related loads powered from offsite power will receive adequate voltage under postulated accident conditions. The licensee's operating control centers have had specific administrative guidance on actions to initiate to keep the 230 KV supply more than one contingency away from reaching 101.3 percent voltage levels. These controls were observed by one of the residents during a visit to the SCS operating center in Birmingham, Alabama and have been discussed in detail with NRR personnel. The overall result of the meetings (the most recent was held on November 16, 1992) was that NRR will conclude their review of the issue and communicate these results to the licensee.

During the EDSFI, the resident inspector on the team noted that the degraded safety bus voltage annunciators were set to actuate at the same voltage level as the degraded bus automatic protective actions would actuate. This did not provide anticipatory information to the operators. The relay would begin to operate at 88.3 percent of 4160V and would actuate in 21.5 seconds at 78.8 percent of 4160V. A DCR was implemented during the most recent Unit 2 refueling outage which replaced the CV-7 alarm relays with solid state type relays. These relays are set to actuate at

voltage levels of 3829V on the 4160V safety buses. A similar DCR is planned for the Unit 1 safety buses during the Unit 1 Spring 1993 refueling outage. During this inspection period, the inspectors noted that the CR alarm response procedures (approved in October 1992) for the safety bus degraded voltage annunciators referred the operators to procedure 34AB-S11-001-0S: Operating with Degraded Voltage. The inspectors could not locate the procedure and were subsequently informed that the procedure had inadvertently not been completed and was currently in the last phases before final approval. The inspectors noted that the existing Operating Order provides adequate specific guidance to the operators for actions required in response to degraded voltage conditions.

The inspectors concluded that the installation of an anticipatory alarm and implementation of the Operating Order have strengthened the licensee's ability to ensure appropriate actions are initiated to protect the plants safety equipment in the unlikely condition of a degraded (but not entirely lost) offsite voltage. A response to the licensee's denial of the violation will be issued after additional review of the issue by the NRC staff. IFI 321,366/92-26-02 is closed.

e. (Closed) LER 366/92-19: SRVs Experience Setpoint Drift Due to Corrosion Induced Bonding. Based on the above review of IFI 321,366/91-04-03, this LER is closed.

f. (Closed) IFI 321,366/90-26-02: Failure to Enter Appropriate TS LCO During Instrumentation Surveillance Testing. This item addressed the licensee's practice of not considering equipment or instrumentation inoperable during TS required testing, even if that testing resulted in the equipment being unable to perform its function. The primary concern of the inspectors involved examples of misuse of the TS "allowed inoperability period" specifically intended for use during surveillance testing. The inspectors had noted instances of equipment not being considered as inoperable while corrective maintenance or troubleshooting was being performed. Additionally, the "allowable period" was used for testing of instrumentation where the TS did not specifically address the "allowable" period. Whenever equipment or instrumentation is incapable of performing its intended safety function for any reason, it must be considered as inoperable (unless the TS contain a specific allowable period which addresses the circumstances) and the appropriate LCO must be entered. This position is clearly stated in GL 91-18. System unavailability tracking was also effected by the practice.

Inspection Report 321,366/92-08 discussed several examples in which TS LCO action statements were not entered despite inoperable or questionable equipment status. Additionally, there were several additional examples in which equipment rendered inoperable for surveillance testing was not tracked as inoperable and the TS

LCO was not entered. The followup of these examples was also placed under IFI 321,366/90-26-02.

The licensee has taken action to ensure that out of service equipment is more rigidly tracked. The inspectors have noted significantly heightened awareness regarding entry into the appropriate TS LCO during routine surveillance testing. Examples include tracking the EDGs as inoperable when they are in the "local" control mode or inoperable for barring over and also tracking the FPM as inoperable during routine testing which causes that monitor to be isolated. A contributing factor in how the operators deal with equipment removed from service is that the Hatch procedures require administrative actions which often would take longer to complete than the duration of the inoperability period itself. These procedural requirements have not been reduced, even for short inoperability periods. Several meetings have been conducted on this issue involving the NRC. During the most recent meeting (May 28, 1992) the licensee questioned the necessity of entry into TS LCOs for several examples involving extremely short inoperability periods. The NRC staff continued to reiterate the GL 91-18 statements regarding inoperability. The issue is primarily administrative in nature. Even for testing which momentarily renders equipment inoperable (for example cycling of the HPCI steam admission valve), the CR operators record the start of the surveillance activity in the CR logs. Additionally, during these activities, the operators and the SS understand that the equipment will not perform its function if called upon during some parts of the testing. Provided that TS requirements are being met, these actions meet regulatory expectations. The specific administrative methods of dealing with equipment inoperability are left to the licensee.

In regards to the specific concern involving the 2 hour "allowable period" for testing of certain instrumentation, several actions were initiated. The misuse of the period for purposes other than surveillance testing was terminated and the inspectors have not identified any additional examples of that problem. To address the deficiency that the 2 hour period was being utilized for instrumentation other than that listed by the TS, the licensee has applied significant resources towards longterm resolution of the problem. The efforts included submittal of requests for complex TS amendments to NRR. Although these actions are not yet fully completed, significant progress has been made and final resolution is expected in the near future.

Based on the inspector's ongoing monitoring of the licensees's actions and as discussed in the above paragraphs, the inspector concluded that the primary concerns of IFI 321,366/90-26-02 have been sufficiently addressed. The inspectors noted that the licensee's internal tracking records for this IFI incorrectly

indicate that no corrective action was necessary to address the concerns, despite the efforts outlined above. Current sensitivity and practices are sufficient to ensure that TS requirements regarding inoperable equipment will be met. This item is closed.

g. (Closed) LER 321/91-33: HPCI Inoperable Due to Component Failure. This LER addressed the failure of relay 1E41-K615 which had caused excessive oscillations in HPCI flow during surveillance testing. The failure of the relay was of an intermittent nature and was not identified as the cause of the failure during initial troubleshooting. Adjustments were made to the EGM circuitry and HPCI was successfully functionally tested. The following day, during the HPCI system response time test, the flow oscillations occurred again. After this failure, during efforts to calibrate the 1E41-K615 flow control unit, it was noted that an intermittent failure was causing the control unit to not successfully transfer from manual to automatic. The problem was traced to a failure of at least one of the internal relays in the 1E41-K615 controller. Those relays were replaced and subsequent testing of the HPCI system was completed satisfactorily. The TS LCO for an inoperable HPCI was not exceeded. The inspectors also noted that the CR operators were able to reduce the flow oscillations by placing the controller in the manual mode.

Although this problem was included as part of a discussion involving corrective actions in Inspection Report 321,366/92-05 (IFI 321,366/92-05-03: Resolution of Degradation Involving Safety Systems), the licensee's action in response to this particular relay failure were appropriate. As discussed in Inspection Report 321,366/92-05, significant improvements in procedures and overall approach to calibration of the HPCI control circuits have been noted since this event.

The inspectors reviewed the maintenance history of the HPCI system and particularly looked for previous failures of these relays. No other instances of such relay failures were noted. The inspectors also concluded that given the intermittent nature of the failure, the problem was identified within a reasonable time. Based on this review, the LER is closed.

8. Exit Interview

The inspection scope and findings were summarized on January 12, 1993, with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings.

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
366/92-34-01	Open and closed	NCV - Missed SBGT 18 Month Surveillance Testing, Paragraph 3a.
321,366/92-34-02	Open	IFI - Missed TS Surveillance, paragraph 3b.
321/92-34-03	Open	IFI - Onsite Radio Communications Problems, paragraph 2d.
366/92-34-04	Open and Closed	NCV - ESF Actuation During LOSP/LOCA EDG Testing, paragraph 3c.

8. Acronyms and Abbreviations

AC - Alternating Current
A/E - Architect Engineer
AEOD - Analysis and Evaluation of Operational Data
AGM-PO - Assistant General Manager - Plant Operations
AGM-PS - Assistant General Manager - Plant Support
ATTS - Analog Transmitter Trip System
BOP - Balance of Plant
BWR - Boiling Water Reactor
BWROG - Boiling Water Reactors Owners Group
CFR - Code of Federal Regulations
CR - Control Room
CRD - Control Rod Drive
CS - Core Spray
CST - Condensate Storage Tank
DC - Deficiency Card
DCR - Design Change Request
DOP - Dioctyl Phthalate
d/p - Differential Pressure
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EDSFI - Electrical Distribution System Functional Inspection
EHC - Electro Hydraulic Control System
EOF - Emergency Operations Facility
ERT - Event Review Team
ESF - Engineered Safety Feature
EST - Eastern Standard Time
FEOC - Forward Emergency Operations Center
FPM - Fission Product Monitor
FSAR - Final Safety Analysis Report
FT&C - Functional Test and Calibration
GE - General Electric Company
GL - Generic Letter

GPC - Georgia Power Company
HEPA - High Efficiency Particulate Adsorber
HNP - Hatch Nuclear Plant
HP - Health Physics
HPCI - High Pressure Coolant Injection System
HVAC - Heating, Ventilation and Air Conditioning
I&C - Instrumentation and Controls
IEEE - Institute of Electrical and Electronic Engineer
IFI - Inspector Followup Item
ILRT - Integrated Leakage Rate Test
IN - Information Notice
IPE - Individual Plant Examination
LCO - Limiting Condition for Operation
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
LOSP - Loss of Offsite Power
LSFT - Logic System Functional Test
MCRECS - Main Control Room Environmental Control System
MG - Motor Generator
MOV - Motor Operated Valve
MSIV - Main Steam Isolation Valve
MWe - Megawatts Electric
MWO - Maintenance Work Order
NCV - Non-cited Violation
NPRDS - Nuclear Plant Reliability Data System
NRC - Nuclear Regulatory Commission
NRR - Office of Nuclear Reactor Regulation
NSAC - Nuclear Safety and Compliance
NSSS - Nuclear Steam System Supply
PCIS - Primary Containment Isolation System
PEO - Plant Equipment Operator
P&ID - Piping and Instrument Diagram
PM - Preventive Maintenance
PSID - Pounds Per Square Inch Differential
PSIG - Pounds Per Square Inch Gauge
PSW - Plant Service Water System
RB - Reactor Building
RCIC - Reactor Core Isolation Cooling System
RFP - Reactor Feed Pump
RHR - Residual Heat Removal
RHRSW - Residual Heat Removal Service Water System
RPS - Reactor Protection System
RTP - Rated Thermal Power
RWCU - Reactor Water Cleanup System
Rx - Reactor
SAER - Safety Audit and Engineering Review
SALP - Systematic Assessment of Licensee Performance
SBGT - Standby Gas Treatment System
SBLC - Standby Liquid Control System
SCS - Southern Company Services
SED - System Evaluation Document
SER - Safety Evaluation Report

SFP - Spent Fuel Pool
SIL - Service Information Letter
SNC - Southern Nuclear Company
SOR - Significant Occurrence Report
SOS - Superintendent of Shift (Operations)
SOV - Solenoid Operated Valve
SP - Suppression Pool
SPDS - Safety Parameter Display System
SRV - Safety Relief Valve
STA - Shift Technical Advisor
SUT - Startup Transformer
TMM - Temporary modifications
TOL - Thermal overload
TS - Technical Specifications
TSC - Technical Support Center
URI - Unresolved Item
VOTES - Valve Operation Test and Evaluate System
WG - Water Gauge