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

Report Nos.: 50-321/92-12 and 50-366/92-12

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: April 19 - May 30, 1992

Inspectors: Scott E. Sparks for 6/18/92
Leonard D. Wert, Jr. Date Signed
Senior Resident Inspector

Scott E. Sparks for 6/18/92
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Resident Inspector

Approved by: Pierce H. Skinner 6/23/92
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Chief, Project Section 3B
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SUMMARY

Scope: This routine, announced inspection involved inspection on-site in the areas of operations including a Unit 1 shutdown, excess flow check valve positioning during some sampling evolutions, and a Unit 1 scram, surveillance testing including a failure to obtain a required stack sample, maintenance activities including recent solenoid valve failures, main control room environmental control system issues, intake structure ventilation system single failure vulnerability, TI 2515/112, and review of open items.

Results: One violation, three non-cited violations and one unresolved item were identified:

The violation addressed a failure to comply with TS requirements concerning excess flow check valves. In addition to the TS compliance problems, several deficiencies were identified in the post accident sampling system procedure. Chemistry department procedural inadequacies have been noted as a weak area in the past. The inspector identified an additional problem with the PASS procedure which would have made it

difficult to obtain a sample under actual post accident conditions. (Violation 321/92-12-01: Failure to Comply with EFCV TS Requirements, paragraph 2c).

The first non-cited violation involved a missed TS required stack sample. The violation was identified by the licensee and was attributed to personnel error. (NCV 321/92-12-02: Failure to Complete TS Required Particulate Sampling of Main Stack Releases, paragraph 3b).

The second non-cited violation involved several single failure vulnerabilities identified by the licensee during a review of the Main Control Room Environmental Control System. Over the past year, various deficiencies and weaknesses have been identified with this system. The licensee has dedicated significant resources and worked closely with the A/E groups to correct the weaknesses. (NCV 321/92-12-03: MCREC System Single Failure Vulnerabilities, paragraph 5).

The third non cited violation involved several examples of unlocked high radiation doors. The unlocked doors were identified by the licensee. (NCV 321,366/92-12-05: Unlocked High Radiation Doors, paragraph 2e).

The unresolved item addresses potential single failure vulnerabilities involving the intake structure ventilation system. The problems were identified by the licensee as a result of their IPE reviews. (URI 321,366/92-12-04: Intake Structure Ventilation System Single Failure Vulnerabilities, paragraph 6).

During observation of control room activities following the loss of two cooling towers on May 20, the inspectors noted a strong performance by the operating shift crew (paragraph 2a).

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
   D. Edge, Nuclear Security 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
   *R. Musser

   * Attended exit interview

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

2. Plant Operations (71707)

   a. Operational Status

      Unit 1 began the reporting period operating at power. On April 29, 1992, at 9:00 p.m., a shutdown was commenced due to elevated temperatures in the drywell. At 3:42 p.m. on April 30, the generator was removed from the line and a manual scram was inserted at 4:26 p.m. This shutdown is discussed in detail in paragraph 2b. Rod withdrawal for plant restart commenced at 8:10 p.m. on May 2, with the reactor attaining criticality at 10:15 p.m. The generator was tied to the grid on May 4 at 3:23 a.m., and the unit reached rated power later that day at 5:45 p.m. On May 8, at 9:50 p.m., the 1B reactor feed pump tripped during weekly oil pump testing. The unit underwent a runback and stabilized at 67 percent power. The feed pump was returned to service and the unit returned to rated power at 12:35 a.m. on May 9. On May 9, at 1:15 p.m., the 'A' cooling tower circulating water return line ruptured. Power was reduced to 520 MWe (100 percent power is normally approximately 780 MWe), the tower was isolated and a circulating water pump was secured. Repairs were completed and the unit was returned to rated power on May 13 at 9:40 p.m. At approximately 2:50 p.m. on May 20, a large leak was identified on the 'C' cooling tower circulating water header. As power was reduced and the 'C' tower was bypassed and isolated, a large leak developed in the 'B' cooling tower. The 1B circulating water pump and 1B reactor feed pump were removed from service. Reactor power was reduced by decreasing recirculation flow and control rod insertion. Power was stabilized at about 4:40 p.m. at approximately 280 MWe. The inspector observed the power reduction and compensatory actions in the control room. The power decrease was performed in a controlled manner by the operating shift. The shift exhibited the proper balance of concern of keeping the unit on line and ensuring that system capabilities and parameters were not violated by referencing appropriate procedures as conditions permitted. Prior to completing repairs on the cooling tower piping, Unit 1 scrammed from 48 percent power on May 23, at 12:26 a.m. when all four turbine control valves went shut. The scram is discussed in detail in paragraph 2d. Following completion of repairs to the cooling tower piping and corrective actions from the scram, rod withdrawal commenced on May 24, at 4:34 a.m. with the reactor becoming critical at 7:00 a.m. The unit was tied to the line on May 25 at 8:15 a.m. and reached rated power on May 26 at 4:46 a.m. Unit 1 operated at power for the remainder of the reporting period.

Unit 2 operated at power during the entire reporting period.

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.

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. While some problems were noted by the inspectors while Unit 1 was being shut down to resolve high drywell temperature problems, strong performance on the part of CR operators was observed during a power reduction due to the loss of two cooling towers.

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.

During the recent startup on Unit 1, the inspectors questioned the STAs about their specific duties and responsibilities as they related to the control of the process computer. As the unit was proceeding toward the target rod pattern, the inspector noted numerous "base crit codes" and "failed LPRMs" on the process computer P1 printout. There does not appear to be any procedural guidance for the STA to follow for these matters. The inspectors further inquired about procedural guidance on process computer program OD-1. These matters and how the STAs interact with the reactor engineering staff will be examined by the inspectors in future inspections.

Several active safety-related equipment clearances were reviewed to confirm that they were properly prepared and executed. Applicable circuit breakers, switches, and valves were walked down to verify that clearance tags were in place and legible and that equipment was properly positioned. Equipment clearance program requirements are specified in licensee procedure 30AC-OPS-001-0S, Control of Equipment Clearances and Tags. No major discrepancies were identified.

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.

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

Reactor Buildings	Waste Gas Treatment Building
Station Yard Zone	Recombiner Building
Turbine Building	Fire Pump Building
Intake Building	Unit 1 Drywell
Diesel Generator	Building Cooling Towers/Flume Area
Discharge (Mixing) Structure	TSC

During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed. No major discrepancies were noted, minor housekeeping or material condition problems were reported to the appropriate shift supervisor for resolution. Paragraph 2b contains a discussion of several items noted during a tour of the Unit 1 drywell.

The inspectors completed a survey as directed by regional management involving the licensee's onsite waste dump. The facility is primarily utilized for construction and demolition debris. No putrescible, chemical, hazardous or radioactive material is permitted. The inspectors reviewed the controls that the licensee maintains over the dump site. It was noted that the licensee performs routine inspections of the dump. Additionally, a brief discussion of the current Landfill Design and Operation Plan (1990) was conducted. The inspectors toured the dump site and noted prominent signs prohibiting unauthorized dumping. No problems were noted.

On May 29, 1992, John Thompson, formerly an engineering supervisor, was named to replace David Edge as Nuclear Security Manager effective June 1, 1992. Mr. Edge has transferred to the corporate office in Birmingham, AL.

b. Unit 1 Forced Outage Due to Drywell Cooling Problems

During the early portions of the inspection period, the licensee determined that the temperatures in the upper portion of the drywell were such that some environmentally qualified equipment located in this area (such as RTDs) would not remain qualified for the remainder of the operating cycle if temperatures were not reduced. Investigations into this matter revealed that an inadequate amount of air flow from drywell 8B cooler was the most likely cause of the increased temperatures. The licensee attempted to increase air flow from outside the drywell by reversing the fans associated with the 8B cooler. These attempts did not have any affect on drywell temperature. On April 29, 1992, a decision was made to shut down the unit so that a drywell entry could be made to precisely determine the cause of the problem.

At approximately 9:00 p.m. on April 29, a power reduction was commenced. During the shutdown, at approximately 2:33 a.m., a recirculation pump runback occurred when removing a reactor feed pump from service due to a slight decrease in reactor water level. The 'B' recirculation pump ran back to 27 percent of rated speed in lieu of the required runback speed of 44 percent. The runback placed the reactor in the region of potential instabilities at 54 percent of rated power and 43 percent rated flow. The operating shift entered abnormal operating procedure 34AB-OPS-058-1S, Reactor Power Instabilities. Because core flow was less than 45 percent and reactor power was above the 80 percent load line, the procedure directed the shift to leave the region of potential instabilities by inserting control rods or increasing core flow to greater than 45 percent. Since the recirculation system would not immediately respond, the region was exited through the insertion of control rods. The inspector reviewed this matter in detail to insure compliance with NRC Bulletin 88-07, Power Oscillations in Boiling Water Reactors. No deficiencies were noted. The inspector observed the majority of the shutdown below 40 percent rated power. Due to the runback discussed above, the shutdown did not proceed in the smooth manner typically observed by the inspectors. On two occasions, power increases were made in order to proceed with the shutdown due to the existing rod pattern and the constraints of the RWM and RSCS. At 3:42 p.m. on April 30, the Unit 1 generator was removed from the line and at 4:26 p.m. a manual scram was inserted.

After shutting down the unit, licensee engineering personnel made an entry into containment to determine the cause of the decreased air flow from drywell cooler 8B.

Personnel determined that the discharge damper from the cooler was closed and therefore not allowing air flow to upper regions of the drywell. The damper was opened and fixed in this position by drilling a hole and bolting the damper handle in place. This modification was performed on each vertically positioned drywell cooling ventilation damper. The inspectors performed a tour of the drywell and observed this repair and the replacement of two RTDs in the upper portion of the drywell. In addition, in response to a problem identified at Peach Bottom, the inspectors and the licensee performed separate inspections of the insulation on SRVs. The licensee determined that the insulation on the 'C' and 'G' SRVs was crushed and needed replacement. The inspectors noted that the insulation on SRV 'L' was not installed properly in that piping was visible through a six inch gap in the insulation. The insulation on these three SRVs was replaced/adjusted. Because of the SRV insulation matter, the improper positioning of the drywell cooling dampers, and previous observations of debris left in the drywell following an outage, the inspectors discussed inclusion of such issues into the drywell "closeout checklist" with the licensee. The inspectors were informed that a SOR is being written to address the SRV insulation issue and consideration will be given to the enhancement of the drywell "closeout checklist." Following completion of work in the drywell, startup of the unit commenced on May 2, at 8:10 p.m.

c. Failure to Comply with Excess Flow Check Valve TS LCO Action Statement (71707) (61726) (Unit 1)

On May 7, 1992, a CR operator questioned the position of the keylock switch for excess flow check valve 1B21-F051C. The switch was in the "open" position. This opens a bypass path within the valve assembly which effectively prevents the check valve from seating against excess flow. (In the "auto" position, spring pressure holds the valve open until overcome by high flow.) Further investigation indicated that the valve had been bypassed for about 18 hours. The switch had been positioned during the performance of procedure 64CH-SAM-007-0S: Automated Sampling/In-Line Analysis of Reactor Coolant and Containment Atmosphere. 1B21-F051C is located in the instrument line for jet pump number 20 flow indicator. This line supplies the reactor coolant flow path for sampling with the PASS. In accordance with section 7.1 of the procedure, a Unit 1 routine (monthly) reactor coolant sample was being obtained with the PASS. Step 7.1.10 contains guidance to request the CR operators to lock the EFCV open if proper flow or pressure parameters are not obtained. Unit 1 TS states that all containment isolation valves and EFCVs shall be operable. While no specific allowable inoperability period is stated, the similar Unit 2 T.S. permits an EFCV to be inoperable for up to four hours. In this instance valve 1B21-F051C had been inoperable for about 18 hours without the T.S. actions being completed. During their review of this incident the inspectors noted the following:

- While the guidance of 64CH-SAM-007-0S specifically allows the EFCV to be locked in the open position if proper sampling parameters are not met, the procedure does not contain any steps to return the switch to the "auto" position.

- In addition to not containing adequate guidance to ensure the EFCV is returned to operable status, the procedure lacked steps requiring independent verification of restoration.

- Apparently the high differential pressure (1000 psig to atmospheric) across the valve during routine sampling results in the necessity to normally bypass the EFCV during PASS operation. However, it appears that a short period of bypassing to reduce the differential pressure should be sufficient. The flowrate for sampling is stated in the procedure as about an eighth of a gallon per minute while the EFCV is expected to seat at flows of 1.7-2.0 gpm.

- The inspectors reviewed Revision 4 of procedure 62CH-SAM-031-0S. The current procedure (64CH-SAM-007-0S) had replaced this procedure in December 1991. The guidance in 64CH-SAM-031-0S directed the technician to call the appropriate unit Shift Supervisor and ask if the appropriate EFCV had actuated. If it had, the technician was to ask if the EFCV could be bypassed "until the operator of the AIMS has flow and pressure." During the development and review of procedure 64CH-SAM-007-0S, this guidance was changed.

- Discussions with CR personnel indicate that the bypassing of the EFCVs (B21-F051C for Unit 1 and 2B21-F051C for Unit 2) for PASS operation without entry into a four hour T.S. LCO action statement is a fairly common practice. CR operators have locked the switch in "open" as directed by the procedure and failed to realize they had entered a LCO.

- During their review of this issue the inspectors identified an additional procedural deficiency in

64CH-SAM-007-0S. When an actual post accident sample is being taken, the sample flow is returned to the torus instead of the radwaste system. The inspector noted that the two valves in the line going to the torus are containment isolation valves (1E41-F121, 1E41-F122) and are not required to be "reset". A review of the logic of the valves control circuitry indicated that the PASS cannot open these valves if they are not reset after an isolation signal. The isolation valves in the sample lines to the PASS are reset by the procedure. The PASS engineer confirmed the inspectors concern. It appears that a post accident sample would have been difficult to obtain utilizing the guidance in the procedure.

The inspectors reviewed documentation (NUREG 0737, item II.B.3) to ensure that bypassing of the EFCV (even for a short period of time) was accepted by the NRC during review of the PASS. In a January 26, 1984 letter to the NRC describing the system, the licensee had stated that it may be necessary to reset the EFCV to initiate sample flow. While it is not explicitly stated, the inspectors concluded this statement does not indicate that the valve would be bypassed for the entire sampling evolution. The NRC SER (September 21, 1984) on the PASS system apparently found this acceptable since no differing statements were made regarding operation of the PASS. The inspectors noted that the SER stated that a flow limiting orifice will limit reactor coolant loss from rupture of a sampling line. The inspectors verified that flow orifices are located in the lines. Additionally, it was noted that criterion 11 of NUREG 0737 item II.B.3 requires the containment isolation valves to shut on containment isolation signals. The inspectors reviewed the applicable drawings and confirmed that containment isolation signals would override the PASS "open" signal to the CIVs in the sampling lines. The valves can be opened if necessary by CR personnel if the isolation signals are overridden. The inspectors reviewed LER 366/90-04 which addressed a problem involving the PASS and secondary containment which had occurred due to an improper procedure revision. While both issues had procedural inadequacies involved, the corrective actions completed for that event would not be expected to have prevented this incident. In 1991, a task force completed a review of all chemistry procedures with emphasis on ensuring that chemistry surveillance TS requirements were being met by the procedures. This review identified several deficiencies which were corrected, but the weaknesses in this procedure were not within the scope of that review.

procedural weaknesses and the failure of the operators to realize the TS requirements involving the EFCVs resulted in a violation of TS. Factors considered in evaluating the safety significance of the violation include the small diameter of the line involved and that the PASS lines are within secondary containment. While the issue was identified through a CR operators questioning, the longterm practice of not entering the appropriate TS LCO during bypassing of the EFCV continues to be a significant weakness. Additionally, significant procedural deficiencies involving the PASS were identified. Deficiencies continue to be identified in chemistry department procedures. This is identified as Violation 321/92-12-01: Failure to Comply with EFCV TS Requirements.

d. Unit 1 Scram Due to Turbine Stop Valve Closure

On May 23, 1992, at 12:26 a.m., Unit 1 scrammed from 48 percent power when all four turbine stop valve went closed. Shift personnel had just completed surveillance procedure 34IT-N30-001-1S, Main Turbine and Auxiliaries Weekly Test, when the scram occurred. This procedure provides instructions for various turbine testing including the stop valve stroke test which was completed prior to the scram. As a result of the scram, reactor water level decreased to a minimum level of zero inches (approximately 162 inches above the top of active fuel) and was recovered by the 'A' reactor feed pump. Additionally, the recirculation pumps tripped as expected. A full group 2 isolation signal was received due to water level decreasing below the scram set point (+12 inches). All group 2 valves closed, but valve 1G11-F019, the drywell equipment drain pump isolation valve, took more than the TS limit of 15 seconds to shut (approximately 16 seconds) as determined from the review of the SPDS tapes of the transient.

Following the scram, the cause of the TSVs closing was not apparent. The licensee formed an event review team to review this and other matters related to the scram. Investigation into the event revealed that the cause of the stop valves closing was the servo valve associated with the number 2 stop valve was not supplying the proper flow of EHC fluid to the number 2 stop valve. Additionally, because stop valves 1, 3 and 4 are slaved to stop valve 2, they close when the number 2 stop valve closes. The servo valve's fine mesh strainer had become clogged with very small non-metallic organic debris which came from the breakdown of a 0.5 micron filter (1N32-F005) in the EHC recirc loop. The licensee concluded the filter apparently malfunctioned because it was manufactured from material which is not compatible with EHC fluid. Prior to returning the unit to service, the licensee replaced the 1N32-F005 filters, the EHC pumps suction and discharge filters, the EHC servo valve fine mesh strainers and the EHC fluid was drained from the system reservoir and replaced with new fluid. Unit 2 filters (2N32-D005) were also replaced. The Unit 2 filters were found to be slightly deteriorated, although there was no evidence of missing filter parts similar to that of the Unit 1 filter.

After the scram and recirc pump trip, the shift attempted to restart the recirc pumps to keep the temperature difference between the steam dome and bottom head drain to a minimum. However, attempts to restart both pumps failed when the pumps discharge valve failed to jog open during the start sequence. The licensee cleaned the auxiliary contacts on both MG set field breakers and were subsequently able to start the recirc pumps. Valve 1G11-F019, which had failed to stroke within its TS required time of 15 seconds, was lubricated and the solenoid valve associated with its actuator was replaced. Subsequent stroking of the valve demonstrated times within TS limits.

Following the above corrective actions, restart of the unit commenced on May 24 at 4:34 a.m.. The inspectors will continue to review the licensee's corrective actions for the event during review of the final event review team report and the LER.

e. Unlocked High Radiation Doors

On April 13, 1992, the inspectors were informed of the discovery of two unlocked high radiation doors on April 12. The unlocked doors were identified during the performance of high radiation door checks in accordance with 62RP-RAD-016-0S: High Radiation Area Access Control. The first door found was fully open and located at the entrance to the Unit 1 RWCU Heat Exchanger Room. The second door found open was the Unit 2B RWCU Pump Room entrance. Both cases were documented on deficiency cards in accordance with plant procedure. Subsequent investigation into these matters by the licensee indicated that the Unit 1 RWCU Heat Exchanger Room was left open by a mechanic performing a TS leakage inspection surveillance and the Unit 2B RWCU Pump Room door was left ajar by an operations PEO performing high radiation rounds. Inspection of the doors by the licensee and the inspector subsequent to the events determined that the doors were functioning properly with no mechanical problems. Plant records indicate that the Unit 1 door was left open for a maximum of seven hours and the Unit 2 door was left open for a maximum of thirteen hours. There was no evidence of any unauthorized entries into the two areas during these periods. The two involved individuals were counseled and subjected to the licensee's discipline program. In both cases, the individuals stated that they did not positively verify that the doors were locked upon leaving the areas. In addition to the two instances of unlocked doors discussed above, the licensee discovered two additional unlocked high radiation doors in 1992. In both of these cases (February 12, 1992 and March 19, 1992), the Unit 1 RWCU Heat Exchanger Room was found unlocked. In the February 12 instance, a maintenance foreman apparently failed to ensure the closure of the door upon his exit. The unlocked door discovered on March 19 was not verified closed on the previous shift by a PEO performing work in the area.

The inspectors reviewed the licensee's corrective actions for these events. In addition to counseling involved personnel, the Plant General Manager issued a management memo to all plant personnel stressing the importance of high radiation controls and that future occurrences could not be tolerated. General Employee Training was also revised to include the responsibilities of an individual signing out a key to a high radiation area by having each employee sign a statement to this affect during training. Additionally, high radiation doors are being upgraded. At present, the Unit 2 upgrade project is approximately 87 percent complete, with the Unit 1 door upgrade scheduled to begin in September 1992. This upgrade adds, replaces and enhances some high radiation doors as well as adding hydraulic closure mechanisms to the doors and would most likely have prevented the four incidents.

The problem of unlocked high radiation doors has continued to be a problem at Plant Hatch. Inspection report 50-321,366/91-33 also addresses this issue. In that report, an unlocked high radiation door discovered by the licensee on December 2, 1991, was identified as another example of violation 321,366/91-05-03. Since the December 2 occurrence, the licensee has discovered a total of four high radiation doors as described above. The four instances of unlocked high radiation doors is a violation of 10 CFR20.203(c)(2)(iii) and TS 6.12.2. This violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria of Section VII.B of the Enforcement Policy. The licensee's surveillance program for high radiation doors discovered two of the instances of unlocked doors, while a HP technician discovered a third door open. This is identified as NCV 50-321,366/92-12-05: Unlocked High Radiation Doors.

One violation and one non-cited violation were identified.

The violation cited in paragraph 2c involves a failure of operations personnel to enter the appropriate TS LCO action statement for an inoperable valve. Several significant procedural problems were also identified. Weaknesses in chemistry procedures have been previously noted as a problem.

3. Surveillance Testing (61726)

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. 34SV-B21-002-1S: Main Steam Line Isolation Valve Trip Test (during Unit 1 Shutdown)

2. 34SV-T48-004-2S: Drywell to Suppression Chamber Leakage Test

3. 34SV-SUV-008-2S: Containment Isolation Valve Operability Testing (as directed by Operating Order 00-01-03925 due to previous sticking ADV solenoids)

4. 34SV-R43-002-2S: Diesel Generator 1B Monthly Test

During the observation of 34SV-SUV-008-2S, the inspector noted that the appropriate TS LCO action statement was entered. The procedure requires the shutdown and isolation of the fission product monitor during part of the test. Previously, the TS LCO action statement for the inoperability of the FPM was not always entered. A review of LCO sheets indicated no entry on last five weekly tests. As discussed in Inspection Report 321,366/92-08, the inspectors have noted that LCOs are not always entered for inoperable equipment. This example shows increased sensitivity toward inoperable equipment status during surveillance testing and entry into the appropriate LCO action statement. The valve testing is being performed at weekly intervals due to a pattern of failures recently identified regarding the involved solenoid operated valves. On May 15, 1992, valve 2B31-F020 reactor coolant sampling outboard isolation valve, failed an operability test apparently due to a sticking solenoid. Paragraph 4b of this report discusses the recent ASCO valve failures.

b. Failure to Obtain TS Required Main Stack Sample (61726)

The inspectors reviewed LER 321/92-008: Personnel Error Results in Missed TS Surveillance. This LER addressed a failure to complete the particulate sampling/analysis of main stack releases required by TS Table 4.15.2-1 (Unit 1) and TS Table 4.11.2-1 (Unit 2). The problem was caused by the failure of a chemistry technician to include a particulate filter in the filter assembly when it was installed in the sampling flow path. TS Table 4.14.2-1 (Unit 1) contains specific requirements to verify the presence of the filter element at the weekly filter changeout. The particulate filter is then isotopically analyzed and the resulting particulate release concentrations are utilized in calculating yearly dose to the public. The LER documents the licensee's review of all other available indications and concludes that the particulate release rate for the week in question (beginning March 17, 1992) was not any higher than the releases calculated for the weeks prior to and after the error occurred.

During their review of this issue, the inspectors also noted that the stack monitor did not alarm or indicate high gross particulate activity levels during the week in question. This failure to complete TS required sampling is a violation. This violation will not be subject to enforcement action, because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section VII.B of the Enforcement Policy. The error was identified by chemistry technicians as the filter assembly was being prepared for analysis. A standing order (SO-HPC-001-0492) was promptly issued by the manager of health physics and chemistry requiring independent verification when filter assemblies are replaced on sampling lines. Sampling of the reactor building vents, the recombiner vents and main stack were included in the order. A procedure change to 64CH-SAM-005-0S: Gaseous Effluents: Sampling, will incorporate this requirement. The inspector reviewed the sampling evolution with chemistry personnel and noted that data form HPX-0344 has been updated to reflect the verification requirements. The event was reported as required. The inspectors noted that the use of independent verification in chemistry department procedures has been increased over the last year. Several deficiencies involving procedural adherence problems or procedural deficiencies have been corrected through this increased application of independent verification. Paragraph 2c of this report discusses procedural weaknesses identified involving the PASS. Shortly after the inspectors had reviewed the corrective actions, they were informed that the independent verification enhancements regarding the sample assembly had been revised to double verification. Since this independent verification action required disassembly and reassembly of the sample assembly by a second individual, the inspector concluded that double verification should be sufficient. This is identified as NCV 50-321/92-12-02: Failure to Complete TS Required Particulate Sampling of Main Stack Releases.

One non-cited violation was identified.

4. Maintenance Activities (62703)

a. 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, 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 1-92-2279 - Repairs to 1D11-K611B (Refueling Flow Radiation Monitor)

2. MWO 1-92-2302 - Investigate and Repair Valve 2G11-F015 (Installation of TMM 1-92-39)

3. MWO 1-92-2113 - Troubleshoot and Evaluate Problems with the Drywell Cooling System

b. Solenoid Operated Valve Failures Due to Sticking Solenoids

On May 15, valve 2B31-F020 failed to stroke within the TS specified time limit. 2B31-F020 is the outboard containment isolation valve in the reactor coolant sampling line. The cause was identified as a "sticking" solenoid valves in the air line to the valves operator. The appropriate LCO action statement was entered and the solenoid was replaced on May 16. The solenoid was an ASCO Model NP206. Other similar failures of this type of solenoid valve have been identified at Hatch. LER 321/92-003: Failure of Solenoid Operated Valves Causes Loss of Emergency Equipment Room Coolers, describes the failure of two such valves. The licensee's review of the issue indicated that NP206 failures have also occurred at the Brunswick and Peach Bottom sites. In February 1992, some of the information obtained by the licensee regarding failures of these valves was forwarded to regional NRC personnel who informed NRR of the failures.

The licensee is continuing the investigation into the cause of the sticking solenoid valves. This model of ASCO valves has not been specifically addressed in NUREG-1275: Operating Experience Feedback Report - Solenoid-Operated Valve Problems.

The licensee is also cycling, on a weekly frequency, several valves which are considered suspect to failure. Additional corrective actions are being evaluated. On May 20, 1992, the licensee conducted a meeting on the failures of ASCO Solenoid Valve Model NP206. During this meeting, the licensee decided to replace all normally energized ASCO NP206 SOVs currently in safety-related applications with a more reliable model (Model NP8320 is being considered). In addition, all model ASCO SOVs in use in safety-related applications at Plant Hatch will be reviewed to determine if they are experiencing similar or additional problems.

No violations or deviations were identified.

The inspectors concluded that the licensee is vigorously pursuing the failed SOV issue. Corrective actions to prevent or reduce future failures appear to be timely and appropriate.

5. Main Control Room Environmental Control System Issues (71707) (92700) (92702) (40500)

During this inspection period, the inspectors reviewed the recent history and status of issues involving the MCREC system. The following is a summary of the significant developments.

In July 1991, the licensee identified two single failure vulnerabilities involving divisional power supplies to the three AC trains of the MCREC system. LER 321/91-09 was submitted to the NRC on this issue. Because several other examples of single failure problems had been identified, the LER stated that a design review of MCREC against the single failure criterion would be completed by December 31, 1991. A modification was completed which corrected the power supply problem. The inspectors reviewed the LER and portions of the MCREC system in detail. Because the power supply single failure vulnerability had not been recognized or corrected despite the information being available to the licensee and A/E since 1989, a violation was written addressing inadequate corrective actions. Inspection Report 321,366/91-20 discussed other potential MCREC problems and stated that in general, MCREC had not been receiving the attention it should given the significance of the system.

In August 1991, the inspectors identified that the MCREC HVAC units had been tripping on high head pressure due to a repetitive plant service water strainer clogging problem. The issue was classified as a weakness since preventive maintenance or a solution had not been developed. Additionally, the inspectors found the standby MCREC HVAC unit control room switch was not being maintained in "standby" as stated in the FSAR. A failure of one of the other AHUs would not result in starting the standby unit as described in the FSAR. (Inspection Report 321,366/91-21)

In September 1991, the inspectors identified that the MCREC system was being routinely operated in a different manner than as described in the FSAR. Deviation 91-23-01 was cited. The CR switch for the standby HVAC unit was again noted in the "off" position. The CR thermostat was not being used to control temperature. Instead of 2 HVAC trains in operation, often only one train was operated. The exhaust fans/dampers were not operated as depicted on drawings or as discussed in the FSAR. The licensee did not supply 10 CFR 50.59 analyses supporting the FSAR deviations. The report stated that onsite knowledge of the MCRCEC system needed improvement. The inspectors noted that testing of the pressurization function of the MCREC was always conducted with 2 AHUs in operation. The inspectors requested that the licensee ensure the actual configuration of the system would not render the pressurization function inoperable. (Inspection Report 321,366/91-23)

In December 1991, testing was performed which indicated that the CR pressurization function (automatically pressurize to at least 0.1 inches of water) was not adversely affected by only one AHU running. SNC and the A/E had reviewed details of the MCREC design and operation that had previously not been well understood.

In April 1992, additional testing was conducted to simulate several potential single failure concerns. As a result of the testing and review, four additional single failure vulnerabilities were identified. Revision 1 to LER 91-09 was submitted on April 29, 1992, and discusses these issues:

- The exhaust ducts for the two CR exhaust fans do not have independent, redundant isolation capability. If one of these fail to close, the pressurization mode is affected. These dampers are normally maintained shut and their fans are only run for testing and if necessary to clear smoke from the CR.

- A similar problem existed regarding the exhaust duct damper from the mens room in the CR. During testing, if the door to the room was shut, pressurization would occur as required even with the damper open. Since the door is usually maintained shut and has an auto closure device, this does not appear to be a safety significant problem. During a tour of the CR on May 15, one of the inspectors identified that the door was blocked open with a trash container. The door was unblocked and management was informed.

- The circuitry to automatically start the standby HVAC unit (B) on a loss of one of the other units required the switch for the running units to not be in "off". As permitted by the procedure, often one of the units (A or C) was left in the "off" position. Testing confirmed that in order to achieve the 0.1 inches required, at least one AHU had to be running to "assist" the booster fans. Anytime that the A or the C unit had been secured improperly, a failure of the running unit would result in no AHUs running and the inability to automatically pressurize to 0.1 inches. Although it is significant that this was not known by the utility until recently, the system would still reach and maintain a positive pressure (about 0.08 inches).

- The incorrect AHU alignment and a failure could have resulted in the initiated booster fan not being in series with a running AHU. As discussed above, the 0.1 inch positive pressure in the TS would not be reached. Again, esting indicates that the CR would reach a positive pressure, but not 0.1 inch.

The LER stated that the cause of the vulnerabilities were less a than adequate design and a lack of full understanding of the design of the MCREC system.

The licensee has completed extensive corrective actions on the identified issues and more is planned. The single failure issues involving one AHU in operation were initially compensated for by requiring 2 AHUs in operation at all times or else entry into an LCO. The power supply issue was corrected by modifications (DCRs). A DCR was performed to change the logic of the "B" AHU. It will start on the loss of a running AHU even if the third AHU is secured. Both booster fans are being maintained in "auto" now (both will start on a pressurization signal) to resolve the other S/F issue. Additional corrective actions involve updating procedures, drawings, and the FSAR to reflect the way the system is actually configured and operated.

One additional problem was identified by the licensee during their review. While it was not addressed in the LER, it was discussed with the residents. The door between the main part of the CR and the "annex" (three small rooms where the SOS, clerk, shift foreman,and the kitchen are located) must be shut in order for the 0.1 inches to be achieved on pressurization. The door is normally maintained open and is manually shut upon a pressurization signal. The TS states that MCREC must be able to automatically pressurize the CR to the 0.1 in.

The inspectors discussed with the licensee that if documentation could not be located which indicated that this arrangement had been accepted by the NRC, the issue should be brought to NRR's attention for resolution. On May 7, 1992, the licensee discussed this problem with NRR personnel. Further discussions will be held. The inspectors noted that testing indicates that with the door open, 0.08 inches of positive pressure is attained. The apparent reason that 0.1 inches is not reached is that unused doors within the "annex" area connect with the TB atmosphere and are not sealed. The doors are not caulked or sealed because routine security testing of the access alarms is required. Additionally, while manual action is required in this case, the TS do not specifically state a time requirement for the 0.1 inches to be reached. Discussions with the system engineer indicate that during testing, whenever the CR access doors are opened, pressure drops to as low as 0.05 inches and then recovers when the doors are closed. A resolution of this problem is actively being pursued and the inspectors will continue to follow the issue.

It was concluded that the licensee did perform good reviews of the system and additional details about MCREC were identified. The licensee had committed to the review in the original LER 91-09 and substantial credit should be given for licensee identification. Overall, in response to the MCREC issues, the licensee has completed two independent reviews of the system, three DCRs, significant in-plant testing, detailed calculations, and an FSAR update package. Since the safety function of the pressurization portion of the system is to limit exposure of CR personnel to within the 10CFR50, Appendix A limits, it appears that the system would have accomplished its function. A key assumption in this evaluation is that the 0.1 inches was selected to ensure a "margin" of positive pressure and the value of the positive pressure is not essential in the system performing its mission. The four single failure vulnerabilities addressed in the revision to LER 91-09 are violations of TS requirements. These violations will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violations meet the criteria specified in Section VII.B of the Enforcement Policy. This is identified as NCV 321/92-12-03: MCREC System Single Failure Vulnerabilities.

One non-cited violation was identified.

The licensee has dedicated significant resources and attention toward the resolution of the MCREC system issues.

6. Intake Structure Ventilation System Single Failure Vulnerability (71707)

approximately 1:00 p.m. on May 21 the inspectors were informed by the licensee that a single failure vulnerability involving the intake structure ventilation system had been identified. The intake structure houses the plant service water pumps, residual heat removal service water pumps, the standby service water pump, and the associated motors. These pumps provide water from the Altamaha River for essential functions including EDG cooling and ECCS room and pump cooling.

The intake structure ventilation system includes three large (38,000 cfm each) roof ventilators or fans mounted directly above the PSW motors. Air flows into the structure through grated openings located on the north wall just below ground level. The fans are near the south end of the building at the roof level and pull air from inside the building to the outside. These fans are controlled by a single thermostat and control panel. With the fans in "auto" (normally 2 fans are kept in this mode), a failure of the thermostat could result in the fans turning off. The licensee's calculation indicate that this could result in the loss of the RHRSW and PSW motors due to overheating. The inspectors have not yet reviewed the calculations, but have been told that the assumptions included 96 degrees F ambient outside temperature and a total of seven pump motors running. (One unit in a "normal" power configuration and the other in a post accident condition). The calculation indicates that in about 2-4 hours without cooling, temperatures could reach 410 degrees F and motor failures will result. There is no indications of fan status or intake building temperatures in the CR. High motor bearing temperatures would result in CR alarms.

After some preliminary review the inspectors concluded that the issue is not an immediate operability issue but past operability is questionable:

- Current outside temperatures are not 96 degrees F. (about 82 degrees)

- The auto dampers on the fans discharges and the intake louvers have been "blocked open" to provide a flow path for heated air to exit the structure.

- Two of the three fans are now caution-tagged to be maintained in the "hand" mode. (These fans will run all the time regardless of the thermostat conditions).

While the licensee does not currently have an analysis which supports operability without the fans as long as the dampers are blocked open, information indicates that the open dampers will permit a sufficient "chimney" effect to maintain operability of the motors. A detailed calculation supporting this will soon be completed. During their review of the licensee's compensatory measures the inspectors noted that two of the four ventilation supply openings are effectively blocked by a stoplog (apparently temporarily stored in front of the openings). The air flow into the building seems to be affected by this factor. Management stated that they had been made aware of the stoplog recently. The inspectors questioned if ventilation calculations assumed air flow into all four openings and if blocking half of the openings would adversely affect temperatures on a loss of the fans. The licensee stated that the results of the calculations are not affected by the presence of the stoplog.

This issue was identified as a result of the licensee's IPE efforts. The SRI has been attending IPE status meetings and the intake ventilation system has been discussed as an area of potential concern. The licensee made a 4 hour emergency notification on May 21 and is continuing to look into the problem. Other potential single failure vulnerabilities are being investigated. The residents are following the licensee's actions and reviewing the issue to verify all potential concerns are being appropriately addressed.

Due to the potentially significant consequences if a failure of the intake structure motors was to occur, the issue was discussed at length with regional management and NRR personnel. After further review and discussions with the licensee, the inspectors concluded that the existing calculations appear to incorporate numerous conservatisms. The licensee is presently intending to further enhance the accuracy of the calculations in the near future. Additionally, regardless of the conclusions reached after refinement of the calculations, the licensee is pursuing improvements in the intake structure ventilation system. This issue is identified as URI 321,366/92-12-04: Intake Structure Ventilation System Single Failure Vulnerability pending additional information.

One URI was identified. The licensee's IPE reviews resulted in the identification of this potential failure issue. The licensee completed compensatory actions to ensure operability of the systems in the intake structure in a timely manner.

7. Review of Licensee Evaluations Regarding Changes to the Environs Around Licensed Reactor Facilities (TI 2515/112) (30702B)

This inspection was performed to verify that the licensee properly evaluated safety issues which had arisen from changes made near the reactor site involving population distribution or the introduction of new industrial, military, or transportation hazards. The following documents were reviewed by the inspectors during this effort:

- Final Safety Analysis Report
- 10 CFR Parts 50.71 and 100
- NRC Generic Letter 81-06, Periodic Updating of Final Safety Analysis Reports
- Annual Radiological Environmental Operating Reports
- SER for the Hatch Nuclear Plant

The inspector held discussions with licensee personnel and determined that a formal program did not exist to periodically review the area around the reactor site for changes to the environs. No requirements were found in the licensee's procedures which require a periodic review of the environs to specifically identify and evaluate site proximity hazards.

However, the licensee does have an informal process of updating the FSAR when changes in population distribution or other changes in environs occur. The informal process consists of periodic discussions with local authorities, local emergency planning organizations, and general knowledge of the area.

The licensee performs TS surveillance 4.16.2 annually, which requires that a land use survey identify the location of the nearest milk animal and the nearest permanent residence in each of the 16 meteorological sectors within a distance of 5 miles. The results of this survey are discussed in the Annual Radiological Environmental Surveillance Report.

The inspectors reviewed chapters 2 and 3 of the FSAR with plant personnel and discussed potentially new safety hazards, and found that the applicable chapters in the FSAR addressed the current safety hazards around the site.

No violations or deviations were identified.

The licensee's method for monitoring the environs for potential hazards was informal. The relatively low population of the surrounding area, as well as the general location of the plant, contributed to the accuracy of the information contained in the FSAR. However, the informal process for updating the information may not be sufficient to maintain this accuracy.

8. 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 321/90-12: Manual Scram and Notification of Unusual Event Due to Fire in Offgas System. This LER addressed the manual scramming of the Unit 1 reactor due to the malfunctioning of the offgas system which resulted in a fire in the carbon adsorber beds. Licensee management directed the reactor be scrammed when it became apparent that the offgas system was no longer operating in a manner which would allow continued operation of the unit. More specifically, due to the failure of several components in the offgas system, the recombination of hydrogen and oxygen was not taking place thus allowing hydrogen concentrations to increase to levels greater that 4 percent. The result of the high hydrogen concentration was a hydrogen ignition and fire in the carbon adsorber vessels. A notification of unusual event was declared due to a fire lasting greater than 10 minutes in the system. Approximately six days later, air samples from the offgas system conclusively determined that the fire was extinguished.

Corrective actions for this event were numerous. First, various components in the offgas system were either repaired or replaced. Specifically, the 1N62-F136/137 (trap bypass valves) were replaced with needle valves, the 1N62-F107B (coil bypass isolation valve) was replaced with a needle valve, the 1N62-F140 A/B (condensate return pump pressure control valves) were replaced and the 1N62-C536B ('B' Condensate Return Pump) was rebuilt. During this portion of the review, the inspector noted that P&ID H-16523 did not reflect that valves 1N62-F107A&B were needle valves and additionally did not reflect that valves 1N62-F136 and 137 were normally closed during system operations. The system engineer indicated that the drawing would be changed to reflect the proper plant configuration. The next series of corrective actions dealt with revisions to procedures which directly affect the operation of the offgas system. The inspector reviewed procedures 34SO-N62-003-1S: Offgas Auxiliary Steam System, 34AB-OPS-038-1S: Failure of Recombiner and Control of Sustained Combustion in the Offgas System, and 34AR-N62-901-1S: Annunciator Response Procedures for the Offgas System, and found the changes/revisions to the procedures to properly implement corrective actions for this event. In addition, procedure 52PM-N62-001-1S: Offgas System Preventive Maintenance was reviewed. The inspector verified that the procedure was acceptable and that the maintenance prescribed by the procedure was scheduled in the licensee's repetitive task data base. Based on this review, LER 321/90-12 is closed.

b. (Closed) LER 321/91-002: Component Failure and Personnel Error Result in Unplanned ESF Actuation. This LER addressed a relay failure (1C61-K24) which resulted in a partial outboard Group 2 primary containment isolation actuation. During replacement of that relay, a technician bumped a different relay and initiated SBGT system and isolated secondary containment. The failed relay was replaced and systems were restored to normal. Personnel were counseled concerning care when working in panels containing such equipment. In many of the CR panels space is very tight during work. The failed relay was a General Electric CR 120A model. Since 1990, three other LERs have been submitted regarding CR 120A relay failure (all were in different components). As stated in the LER, NPRDS data indicates a low failure rate for the relays. LER 321/91-002 is closed.

c. (Closed) LER 321/91-003: Component Failure Results in ESF Actuation. This LER addressed an instance of the

MCREC system shifting to the pressurization mode. The actuation was caused by a failed fuse inside a power supply to the refueling floor area radiation monitors. The system responded as expected. The fuse was replaced and the system was returned to normal. No other MCREC pressurization actuations due to the power supply fuse failing have occurred either previous to or since this incident. LER 321/91-003 is closed.

d. (Closed) LER 321/91-004: Component Failure Causes Turbine Trip and Reactor Scram. Vibration induced failure of an EHC pressure switch caused a scram and some of the SRVs did not lift within the T.S. allowable limits. Inspection Report 321,366/91-04, contains a detailed description of this event and the corrective actions taken to prevent future occurrence. The SRV setpoint drift issue is a long standing problem among BWR 4 facilities. Hatch is currently pursuing a solution to this problem (ahead of the BWROG plan). NRR is reviewing the licensee's proposed design modification. IFI 91-04-03: SRVs not lifting at T.S. setpoints will be used to continue following the licensee's actions. Based on the review discussed in Inspection Report 91-04 and this review, LER 321/91-004 is closed.

e. (Closed) LER 321/91-10: Improper Installation of Relay Results in ESF Actuation. This LER addressed an actuation of valve 1E51-F105 (RCIC turbine exhaust vacuum relief line isolation) when a technician inadvertently bumped a rear mounted HGA relay in CR panel 1H11-P623. Inspection Report 321,366/91-18 contains a discussion of this event. The inspectors identified the NSAC investigation of the issue as a strength. Detailed review revealed that improper wire routing had caused the relay covers to be incorrectly installed and susceptible to actuating the contacts. Future inadvertent equipment actuations or other problems (which could have resulted by the improper installation practice) were prevented. The licensee inspected all rear mounted HGA relays in safety related panels. Since many of the relays are located in crowded panels, corrective actions were delayed until the next outage as appropriate. By November 1991, all susceptible HGA relays were inspected and necessary corrective actions were completed on both units. In numerous cases, no cover was found on the relays. SCS evaluated the absence of the relay covers and concluded that the seismic qualification of the relays or panels was not adversely effected. The licensee did not install covers on some of the relays (particularly those located within cabinets where dust would not be a concern). LER 321/91-10 is closed.

f. (Closed) Violation 321,366/91-27-02: Inadequate Corrective Actions Regarding Service Water Cooling Coil Coupling Failures. The licensee has installed new cooling coils (of an enhanced design) in all of the PSW motors. As discussed in the follow-up response to the notice of violation, the new coils for the RHRSW pump motors have not yet been received. Once they are delivered to the site, the new coils will be installed (in conjunction with performance of routine preventive maintenance) as scheduling and maintenance resources permit. The more generic concerns in this issue regarding timely identification and resolution of repetitive equipment problems will be addressed by actions in response to IFI 321,366/92-05-03: Resolution of Degradations Involving Safety Systems. Violation 321,366/91-27-02 is closed.

g. (Closed) LER 321/90-07: Errors in Feedwater Flow DP Transmitter Calculations Result in 1% Thermal Overpower. This voluntary LER addressed a design calculation error identified by the licensee on April 19, 1990, involving an omitted span correction factor for the DP transmitters and an incorrect area thermal expansion coefficient for the feedwater flow elements. These errors combined to result in non-conservative feedwater flows and an actual thermal power of approximately 1% greater than indicated thermal power.

The licensee identified these errors in response to Service Information Letter 452, Supplement 1, "Feedwater Flow Element Transmitter Calibration", dated November 18, 1988. The licensee subsequently determined that the original design calculations performed by the Nuclear Steam Supply vendor were incorrect. At the time these errors were confirmed by the licensee, Unit 1 was in the Refuel mode with the core completely loaded, and Unit 2 was at approximately 98% rated thermal power. Corrective actions for this event included administratively de-rating Unit 2 to 98% rated thermal power until flow transmitters 2C32-N002A and B could be recalibrated using the guidance of SIL 452, Supplement 1. The corrected calibration factors were incorporated into procedure 57CP-CAL-069-2S, Rosemont Model 1151AP, DP and GP Transmitter, and the Unit 2 transmitters were recalibrated on 4/21/90. The Unit 1 transmitters were recalibrated prior to startup.

The licensee also performed a safety assessment and determined that operation slightly above rated thermal power (1%) did not impair the ability of either Unit 1 or Unit 2 to achieve and maintain a safe shutdown condition, or violate any applicable safety analyses. This LER is closed.

h. (Closed) IFI 366/90-17-01: Completion of ATWS Upgrades for Unit 2. This item was used to follow the completion of modifications to the Unit 2 ARI system. The modifications allow testing of the four final actuation relays at power and ensure manufacturer diversity between RPS and ARI. The modifications had been previously completed on Unit 1 and was reviewed during the TI 2500/020 inspection. DCR 89-107 was implemented and successfully tested on Unit 2 in May 1992. Problems with the implementation procedure resulted in inadvertent initiation of several ESF systems. Violation 366/91-15-01: Incorrect Procedure Resulting in Unanticipated ESF Actuations, and LER 366/91-012 addressed that problem. The inspectors verified that several portions of the work described in DCR 2H89-107 were completed. Since the Unit 1 ARI system (with the modification) had been previously inspected, the design was not reviewed against the specific ATWS requirements. This item is closed.

9. Exit Interview

The inspection scope and findings were summarized on June 1, 1992, 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
50-321/92-12-01	Open	Violation - Failure to Comply with EFCV TS Requirements (paragraph 2c)
50-321/92-12-02	Opened and Closed	NCV - Failure to Complete TS Required Particulate Sampling of Main Stack Releases (paragraph 3b)
50-321/92-12-03	Opened and Closed	NCV - MCREC System Single Failure Vulnerabilities (paragraph 5)
50-321,366/92-12-04	Open	URI - Intake Structure Ventilation System Single Failure Vulnerabilities (paragraph 6)

50-321,366/92-12-05	Opened and Closed	NCV- Unlocked High Radiation Doors (paragraph 2e)

10. Acronyms and Abbreviations

AC - Alternating Current
A/E - Architect Engineer
AHU - Air Handling Unit
AIMS - Automated Isotopic Measurement System
APRM - Average Power Range Monitor
ARI - Alternate Rod Insertion System
ASCO - Automatic Switch Company
ATWS - Anticipated Transient Without Scram
BWROG- Boiling Water Reactors Owners Group
CFR - Code of Federal Regulations
CIV - Containment Isolation Valve
CR - Control Room
CRD - Control Rod Drive
DC - Deficiency Card
DCR - Design Change Request
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EFCV - Excess Flow Check Valve
EHC - Electro Hydraulic Control System
EQ - Environmental Qualification
ESF - Engineered Safety Feature
EST - Eastern Standard Time
FPM - Fission Product Monitor
FSAR - Final Safety Analysis Report
FT&C - Functional Test and Calibration
GE - General Electric Company
GPM - Gallons per Minute
HELB - High Energy Line Break
HP - Health Physics
HPCI - High Pressure Coolant Injection System
HVAC - Heating, Ventilation and Air Conditioning
I&C - Instrumentation and Controls
IFI - Inspector Followup Item
IPE - Individual Plant Examination
IRM - Intermediate Range Monitor
LCO - Limiting Condition for Operation
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
LPRM - Local Power Range Monitor
MCRECS- Main Control Room Environmental Control System
MWe - Megawatts Electric
MWO - Maintenance Work Order
NCV - Non-cited Violation
NRC - Nuclear Regulatory Commission
NRR - Office of Nuclear Reactor Regulation
NSAC - Nuclear Safety and Compliance
PASS - Post Accident Sampling System

PCB - Power Circuit Breaker
PCIS - Primary Containment Isolation System
PEO - Plant Equipment Operator
PM - Preventive Maintenance
PSIG - Pounds Per Square Inch Gauge
PSW - Plant Service Water System
RCIC - Reactor Core Isolation Cooling System
RFP - Reactor Feed Pump
RHRSW- Residual Heat Removal Service Water System
RPS - Reactor Protection System
RPT - Recirculation Pump Trip
RSCS - Rod Sequence Control System
RTD - Resistance Temperature Detector
RTP - Rated Thermal Power
RWCU - Reactor Water Cleanup System
RWM - Rod Worth Minimizer
Rx - Reactor
SAER - Safety Audit and Engineering Review
SCS - Southern Company Services
SER - Safety Evaluation Report
S/F - Single Failure
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
SRM - Source Range Monitor
SRV - Safety Relief Valve
STA - Shift Technical Advisor
TS - Technical Specifications
TSC - Technical Support Center
TSV - Turbine Stop Valve
URI - Unresolved Item