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

Report Nos.: 50-321/96-02 and 50-366/96-02

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

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

Facility Name: Hatch 1 and 2

Inspection Conducted: January 7, 1996 - February 17, 1996

Inspectors: For R. W. Wright 3/13/96
Bob L. Holbrook, Sr. Resident Inspector Date Signed

For R. W. Wright 3/13/96
Edward F. Christnot, Resident Inspector Date Signed

M. Miller, Electrical Inspector
R. Gibbs, Reactor Inspector
J. Lenahan, Reactor Inspector
C. Smith, Reactor Inspector
R. Chou, Reactor Inspector
D. Jones, Chemistry/Radiological Effluent Inspector

Accompanying Inspector: James A. Canady

Approved by: ______________________ Date Signed
Pierce H. Skinner, Chief,
Reactor Projects Branch 2
Division of Reactor Projects

SUMMARY

Scope:

Inspections were conducted by resident inspectors and regional inspectors in the areas of plant operations which included; routine operations, self assessment, Code of Federal Regulation posting requirements, and inspection of open items; maintenance which included routine maintenance work activities, surveillance testing, plant re-engineering and performance team implementation, and inspection of open items; engineering which included, design change control processes, review of engineering backlog, quality assurance assessment and oversight, engineering response to emergent issues, modifications and modification installation and testing, review of activities in response to Information Notice 96-07, Slow Five Percent Scram Insertion

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Times Caused by Viton Diaphragms in Scram Solenoid Pilot Valves, and inspection of open items; and plant support which included routine health physics and security activities, radioactive effluent monitoring instrumentation, control room emergency ventilation systems, an emergency preparedness exercise and inspection of open items. The inspectors also reviewed commitments in the applicable sections of the Updated Final Safety Analysis Report.

The inspectors conducted back shift inspections on the following dates: January 7, 17, 27, 28, February 1, 7, 8 and 13, 1996.

Results:

One weakness and one unresolved item were identified.

Plant Operations:

The inspectors identified a weakness in managements previous efforts to implement effective problem resolution measures to prevent the use of rigging devices that had not been recently inspected or color coded. The inspectors identified a strength in the licensee's audit process for self assessment. Deficiencies were identified and brought to managements attention for resolution. (paragraph 2.2).

The inspectors reviewed the licensee's actions with respect to the Code of Federal Regulation requirements for the Nuclear Regulatory Commission Form 3 postings and concluded that the forms were appropriately posted, were not defaced and were in sufficient number for appropriate review by licensee employees (paragraph 2.3).

Maintenance:

The inspectors concluded that routine maintenance work activities observed were accomplished in a satisfactory manner and no deficiencies were identified. In addition, the equipment examined in the local area was well maintained (paragraph 3.0.1, 3.0.2, and 3.0.3).

Surveillance testing conducted for the Unit 2 Reactor Core Isolation Cooling System, the Unit 1 Analog Transmitter Trip System, and the 1C Emergency Diesel Generator, were conducted as required by procedures and Technical Specifications in a professional manner using calibrated test instruments. Plant locations observed during the tests were very well maintained (paragraphs 3.1.1, 3.1.2, and 3.1.3).

Observation of surveillances performed on the Unit 1 Reactor Core Isolation Cooling system, the Unit 2 Main Steam Line Radiation Monitors, and portions of the Unit 1 Analog Transmitter Trip System, did not detect any deficiencies. The testing was performed in accordance with procedures by personnel knowledgeable in both the equipment and the procedures. The care taken, by both operations personnel and instrument technicians, to ensure they were working on the right component was noted to be a particular strength (paragraphs 3.1.4, 3.1.5, and 3.1.6).

The inspectors review of licensee performance following the implementation of the performance team concept for re-engineering did not identify deficiencies. The inspectors concluded the effectiveness of maintenance scheduling and work activities, that affected safety related equipment performance or availability, had not declined (paragraph 3.2).

Engineering:

Adequate controls were in place to ensure effective implementation of design changes. The licensee's design change program complied with Nuclear Regulatory Commission requirements (paragraph 4.1).

The licensee effectively managed it's engineering work backlog and completed engineering work activities in a timely manner (paragraph 4.2).

Audits of engineering activities were effective in identifying engineering performance deficiencies and were useful in providing oversight to management. Corrective actions in response to the audit findings were acceptable (paragraph 4.3).

On site engineering support for the implementation of plant modifications was above average in that a Quality Control function was being performed by site engineering personnel during the review of Design Change Requests prior to implementation. Deficiencies found were transmitted to the off-site engineering organization for correction. Based on the results of audits reviewed the licensee's self assessment activities appeared to be effectively implemented. Additionally, the audit results demonstrated good engineering technical support for the Unit 2 Power Up-rate Program. Audit report 95-SA-7 was determined to be a quality product (paragraph 4.3.1).

The audits of engineering activities were effective in identifying engineering performance deficiencies, and were useful in providing valuable information and trend direction to management. Corrective actions in response to the audit findings were adequate and effectively implemented. The auditors were knowledgeable and skillful in the performance of audits and identification of problems (paragraph 4.3.2).

The licensee's system for responding to engineering issues was effective. No examples were identified where a lack of response from engineering personnel had delayed resolution of problems (paragraph 4.4).

The design change and minor design change request had been implemented in accordance with the licensee's design change procedures and requirements. The inspectors reviewed the temporary shielding associated with the main control room and concluded that the temporary shielding did not present any seismic loading or plant operational concern (paragraph 4.5).

Design change request packages reviewed were determined to be technically adequate and had been prepared in accordance with the controls of the American National Standards Institute (ANSI) N45.2.11-1974 design control program. Deletion of ANSI N45.2.13-1976 from section 2.1.1 of the procurement specification for the replacement of the 1A Emergency Diesel Generator was identified as unresolved item 50-321/96-02-01, Deletion of Quality Requirements For Purchase of Replacement Emergency Diesel Generator, pending additional review by the Nuclear Regulatory Commission (paragraph 4.5.1).

Audits of engineering activities were conducted in depth and were sufficient to identify deficiencies. Load calculations for the station service transformer deratings were adequate for connected loads (paragraph 4.5.2).

The calculation to support diesel generator replacement was performed in accordance with the industrial standards and good practices (paragraph 4.5.3).

Reviews and observations associated with the 1B emergency diesel generator modification disclosed that on line maintenance was generally scheduled, well controlled and completed in a timely manner based on past maintenance experience (paragraph 4.6).

Based upon the licensees efforts in evaluating Information Notice 96-07 and other vendor supplied documents describing potential problems with scram solenoid pilot valve diaphragms, and considering the sites favorable past valve operating history, the solenoid valve diaphragm degradation problem identified at other sites was not a problem for the licensee (paragraph 4.7).

Plant Support:

The licensee has effectively implemented a program for maintaining radioactive effluent monitoring instrumentation in an operable condition and performed required surveillances to demonstrate their operability (paragraph 5.1).

The licensee has established procedures to demonstrate operability of control room emergency ventilation systems and has performed required surveillances at the frequency specified in the Technical Specifications (paragraph 5.2).

The licensee's performance during the January 31, emergency preparedness exercise was very good. Although one exercise objective was not met, no significant deficiencies were identified (paragraph 5.3).

Inspector Follow-up Item 50-321,366/95-05-01: Post Accident Sampling System Program Enhancements, will remain open pending installation of new sampling valves (paragraph 5.4).

REPORT DETAILS

Acronyms used in this report are defined in paragraph 9.

1.0 Persons Contacted

Licensee Employees

G. Austin, System Engineer, Engineering Support
@B. Arnold, Supervisor, Chemistry
@G. Barker, Superintendent, Maintenance Support
J. Beck, Team Leader, Shift Team "A"
@*J. Bennett, Chemistry Superintendent
S. Bethay, Engineering Manager, SNC
*J. Betsill, Operations Manager
J. Branum, Project Engineer, SNC
#K. Breitenbach, Engineering Supervisor
D. Brock, Design Team Leader, SNC
@I. Buchans, Team Leader, Surveillance Performance Team
R. Burns, Plant Operator
#+C. Coggins, Engineering Support Manager
D. Crowe, Hatch Licensing Manager, SNC
S. Curtis, Operations Support Superintendent
@*D. Davis, Plant Administration Manager
*M. Davis, Licensed Plant Operator
W. Flowers, Safety Audit and Engineering Review
#@*P. Fornel, Performance Team Manager
#+*O. Fraser, Safety Audit and Engineering Review Supervisor
E. Gibson, Reactor Engineering Supervisor
R. Godby, Maintenance Superintendent
#*M. Googe, Acting Manager, Modifications and Maintenance Support
R. Grantham, Acting Training and Emergency Preparedness Manager
J. Hammonds, Regulatory Compliance Supervisor
*W. Holt, Outages and Planning Supervisor
R. Hukill, Team Leader, Performance Team No. 5
W. Kirkley, Health Physics and Chemistry Manager
S. Lee, Foreman, Chemistry
*J. Lewis, Training and Emergency Preparedness Manager
C. McDaniel, Acting Plant Administration Manager
R. McDonald, Modifications Field Engineer
R. McGinn, Security Operations Supervisor
@V. McGowan, Supervisor, Chemistry
#@T. Metzler, Acting Manager Nuclear Safety and Compliance
#@*C. Moore, Assistant General Manager - Plant Support
C. Page, Assistant Team Leader, Shift Team "E"
#@*J. Payne, Senior Engineer
R. Reddick, Emergency Preparedness Coordinator
P. Roberts, Outages and Planning Manager
#J. Robertson, Acting Manager, Modifications and Maintenance Support
*J. Sellers, Operations Shift Supervisor

#*V. Shaw, Engineering Support Supervisor
@D. Smith, Chemistry Superintendent
#+@*H. Sumner, General Manager - Nuclear Plant
J. Thompson, Nuclear Security Manager
#@*S. Tipps, Nuclear Safety and Compliance Manager
J. Watts, Operations Shift Supervisor
#@*P. Wells, Assistant General Manager - Operations
+A. Wheeler, Jr., Acting Manager - Modifications and Maintenance Support
T. White, Fix It Now (FIN) Team Member
C. Wiggins, Engineer, Plant Modifications
D. Yates, Structural Engineer, SNC

Other licensee employees contacted included office, operations, engineering, maintenance, chemistry/radiation, and corporate personnel.

@Attended Exit Interview on January 12 (Jones, Miller)
+Attended Exit Interview on January 19 (Lenahan)
#Attended Exit Interview on February 16 (Smith, Chou, Gibbs)
*Attended Exit Interview on February 26 (SRI)

2.0 Plant Operations (71707) (40500) (92901)

Activities within the control room were routinely monitored. 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 SPDS was monitored. Control Room observations also included ECCS lineups, containment and secondary containment integrity, reactor mode switch position, scram discharge volume valve positions, and rod movement controls.

Observed activities were conducted as required by the licensee's procedures. The complement of licensed personnel on each shift met or exceeded the minimum required TS. Observed operating parameters were verified to be within TS limits.

2.1 Plant Status

Unit 1 began the report period at 98% RTP in a refueling outage coast down. The unit was at 85% RTP at the end of the report period.

Unit 2 began the report period at 100% of the new 2558 Mwt power limit. The unit operated at 100% RTP for the remainder of report period with the exception of scheduled power reductions for routine testing.

2.2 Licensee Self Assessment

The inspectors conducted a review of licensee self assessment activities. A detailed review of three audits was conducted. Two audits were conducted by SAER personnel and one, a three year FPP audit, was conducted by independent auditors outside the parent organization.

Audit Report 95-SA-8: Unit 2 Startup Activities, was reviewed. The audit was conducted during startup of Unit 2, following the November 1995, refueling outage. The scope of the audit was operator performance during the unit startup. Even though the audit did not identify any findings, the inspectors concluded the audit was thorough and comprehensive. The audit checklist and satisfactory performance criteria were based upon plant procedures and directives. The inspectors observed that the audit was conducted by trained personnel with NRC SRO license experience. The audit results were consistent with the inspectors recent observations of operator performance.

The inspectors reviewed Audit Report 95-FP-1: Fire Protection Program. The audit satisfied the licensee's triannual FPP audit requirement. The audit consisted of direct observation of work and test activities, walkdown of systems and equipment, interviews and document review. The inspectors observed that audit findings were identified. The audit documented that the FPP was "generally adequate". The inspectors reviewed the audit finding responses and concluded they were adequate and timely. Some of the audit findings reflected new requirements of NFPA 20. Other findings were administrative in nature and identified areas where the FPP could be enhanced.

The inspectors discussed some findings with fire protection personnel to gain a better understanding of the long term corrective actions. The inspectors concluded the long term corrective actions were adequate and that licensee management was supportive of the FPP needs. The inspectors also concluded that the FPP was adequately maintained and that the detailed audit accurately reflected the FPP.

The inspectors reviewed Audit Report 95-SA-6: Outage Activities. The audit was conducted during the November 1995, Unit 2 refueling outage and consisted of observation of ongoing work activities. Several audit findings were identified and audit comments were submitted for areas of improvement.

One audit finding identified two examples where rigging devices that had not been currently inspected and did not contain the current test color code were used by contract personnel. This issue was a problem previously identified by the inspectors in 1994. IR 50-321,399/94-31, documented a NOV and other NRC concerns associated with improper construction, testing and use of unmarked rigging devices. The inspectors had discussed licensee managements expectations, corrective actions and control of contractor activities following identification of this issue.

During and after the November 1995, Unit 2 refueling outage the inspectors had observed two occasions where rigging devices that had not been currently inspected had been placed in the equipment staging area for ongoing work activities. However, the inspectors did not see the rigging devices actually being used. These observations were discussed with licensee management. The inspectors identified one example where a rigging device that contained an expired inspection color code was used by contract personnel. This deficiency was immediately brought to the attention of licensee management who was observing the ongoing work activity and the problem was corrected. The manager was not certain of the current color code marking that indicated the rigging devices were recently tested.

The inspectors discussed the audit findings with licensee management to gain their perspective of the recurring problem. Management stated that their expectations had not been met and additional actions were being evaluated to prevent recurrence. Licensee management had not submitted their corrective action plan for these audit findings as of the end of this inspection period.

The inspectors reviewed procedure 52IT-MLH-005-OS: Rigging Inspection Procedure, Revision 2. The applicability section of the procedure stated in part that the frequency of the procedure was prior to placing rigging equipment in service and annually. However, step 7.1.5, Annual Inspection, stated in part, that once per year during a period of November through February, all rigging devices on site shall be visually inspected and shall be marked with a distinct color paint to signify current years's inspection. Any rigging device not displaying the current cod color by March 1 shall not be used until this inspection and marking takes place.

The inspectors had previously discussed the procedure with licensee management and pointed out that some portions of the procedure could be confusing as to when rigging devices would be inspected prior to use. Licensee management's position at that time was that not all rigging devices would be inspected, especially rigging that was in locked equipment storage areas or in tool cabinets. However, their expectations were that all rigging devices would be inspected and color coded prior to use.

The inspectors concluded that several factors possibly contributed to the use of rigging devices that had not been recently inspected or color coded. These included unclear procedural requirements, availability of rigging devices that were not currently inspected, tested or color coded, employee failure to follow procedure to ensure the rigging devices were inspected and color coded prior to their use, and a lack of supervisory oversite.

The inspectors concluded that managements efforts to prevent recurrence of a previously identified problem was ineffective. The inspectors identified managements previous efforts to implement effective corrective actions to prevent the use of rigging devices that had not been recently inspected or color coded as a weakness.

The inspectors identified a strength in the licensees self assessment process to identify recurring problems and bring them to management attention.

2.3 Notice to Employees

10 CFR 19.11, Posting of notices to workers, require the licensee to prominently post current copies of NRC Form 3. The postings shall be in a sufficient number of places to permit individuals engaged in licensed activities to observe them on the way to or from any particular licensed activity location to which the document applies, shall be conspicuous and shall be replaced if defaced or altered.

The inspectors reviewed several NRC Form 3 postings and observed that they were the new form dated September 1995. The inspectors concluded that the forms were appropriately posted, were not defaced and were in sufficient number for appropriate review by licensee employees.

2.4 Inspection of Open Items

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

2.4.1 (Closed) VIO 50-321/94-27-01: Failure to Follow Procedure During Unit 1 Refueling Activities.

This item was identified when personnel error resulted in two out-of-sequence fuel bundles were moved from the core to the SFP. The inspector reviewed the licensee's response to this violation in correspondence dated December 28, 1994. Some of the licensee's corrective actions were: The SRO and licensed operator were temporarily removed from fuel movement duties and were counseled regarding their actions; enhanced operator aids were provided to the licensed operator and the SRO; an additional person was assigned to function as second fuel movement verifier; and fuel movement data sheets were revised to provide fuel assembly orientation in the core. During the subsequent refueling, outage no fuel movement errors were noted. Based upon the inspectors review of licensee's actions and satisfactory operator performance during the last refueling outage this item is closed.

2.4.2 (Closed) VIO 50-321,366/94-27-02: Inadequate Corrective Actions Regarding Fuel Movement Errors.

This item was identified when effective corrective actions were not established for an error on April 15, 1994. This failure contributed to a similar event on September 24, 1994. The inspector reviewed the licensee's response to this violation in correspondence dated December 28, 1994. The corrective actions included the actions taken for VIO 321/94-27-01. Additional actions were taken with one individual who was involved in the April 15 and September 24 errors. This individual was required to make a presentation to the GM on causes of errors and to provide recommendations to reduce the chances of fuel movement errors. Specific directions and training were given to the individual prior to resumption of fuel movement duties. Based on the inspector's review of licensee's actions and satisfactory fuel movement performance during the last refueling outage, this item is closed.

One weakness was identified concerning ineffective corrective actions for rigging test controls.

3.0 Maintenance (62703) (61726) (92902)

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

3.0.1 MWO 2-95-3128: Pump 2P41C002 - Run Pump And Adjust Packing

On January 10, the inspectors observed maintenance personnel performing corrective maintenance for the Unit 2 Service Water pump using procedure 51-GM-MME-002-OS: Maintenance of Centrifugal Pumps and 52-PM-P41-033-2S: Service Water System Preventative Maintenance. Maintenance personnel followed the procedures for adjusting the seal water packing leakage within the required limits of 30 to 60 drops per minute. However, the leakage rate could not be maintained within the limits. It increased to greater than 60 drops per minute after the pump had been run for several hours. Maintenance personnel concluded the packing could not be adjusted within the leakage limits and recommended that it be replaced in the upcoming spring outage. All work observed was accomplished in a satisfactory manner.

3.0.2 MWO 1-96-183: Pressure Indicator 1C11R008 - Gauge is Indicating a Low Pressure, Repair or Replace as Necessary and Calibrate.

On January 11, the inspectors observed I&C personnel trouble shoot to determine the problem and calibrate pressure gauge, 1C11R008. The calibration procedure used by I&C technicians was 57CP-CAL-137-OS: Pressure Gauges.

The inspectors verified that the M&TE used for the calibration had a current calibration sticker. All work observed was accomplished in a satisfactory manner. In addition, the inspector examined all the equipment in the local area and concluded it was well maintained.

3.0.3 MWO : ~~-82: Differential Pressure Transmitter 1E11N007B - Trouble Shoot Transmitter For False Signals.

On January 12, the inspectors observed I&C personnel trouble shoot and determine that an air bubble caused pressure transmitter 1E11N007B to provide a false signal. After clearing the air bubble, the I&C technicians calibrated the transmitter using calibration procedure 57CP-CAL-103-1S: ITT Barton MODEL 764 Differential Pressure.

The inspectors verified that the M&TE had a current calibration sticker. All work observed was accomplished in a satisfactory manner and no deficiencies were identified. In addition, the equipment examined in the local area was well maintained.

3.1 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. Witnessed tests were inspected to determine that procedures were available, test equipment was calibrated, prerequisites were met, tests were conducted according to procedure, test results were acceptable and system restoration was completed. The following surveillances were reviewed and witnessed, in whole or in part:

3.1.1 34SV-E51-002-2S: RCIC Pump Operability

On January 10, operations and maintenance personnel conducted a quarterly operability test of the Unit 2 RCIC pump. In addition, the system engineer also followed the test to monitor the data and assist the test personnel as requested.

The inspectors observed the licensee personnel conduct the test as required by the procedure. The inspectors verified the test run was satisfactorily performed and the data observed was within the TS requirements. The licensee personnel conducted the test as required by procedure in a professional manner. In addition, the inspectors walked down the RCIC area and concluded it was very well maintained.

3.1.2 57SV-SUR-014-1S: Unit 1 ATTS Panel 1H11-NP928 Channel Functional Test And Calibration

On January 10 and 11, the inspectors observed I&C maintenance personnel conduct functional tests and calibrate the trip units for Channels 1B21-N690F, 1E21-N652B, and 1E21-N655B. The inspectors verified the tests and calibrations were performed and were within the acceptance criteria of the surveillance procedure. The I&C technicians performed the surveillance in a professional manner using calibrated M&TE.

3.1.3 34SV-R43-003-1S: Diesel Generator 1C Monthly Test

On January 17, the inspectors observed an operations pre-evolution briefing and performance of a monthly operability test of the 1C EDG. The inspectors observed that operations personnel conducted the pre-evolution briefing in accordance with established procedures. The inspectors verified the surveillance was conducted in accordance with procedures and the test data observed met the TS acceptance requirements.

3.1.4 57SV-D11-016-2S: Functional Test of The Unit 2 Main Steam Line Radiation Monitors.

The test was performed to meet Technical Surveillance Requirement 3.3.11.2 of the Unit 2 Technical Requirements Manual. The inspectors observed procedure adherence, and data collection by the I&C technicians. After the test was completed the inspectors obtained a copy of the data for this test, as well as, the previous test performed on these monitors. The inspectors reviewed this data and the technical requirements in the TRM and verified that the test had been accomplished at the required frequency, and the test procedure met the intent of the testing requirements. The inspector also reviewed FSAR section 7.6.3.1 concerning these monitors.

3.1.5 57SV-SUV-013-1S: Functional Test of the Analog Transmitter Trip System.

The test was performed to meet surveillance requirements SR 3.3.5.1.2, 3.3.5.1.4, 3.3.6.1.2, 3.3.6.1.5, and 3.3.3.1.2 of the Unit 1 TS. The inspectors observed procedure adherence and data collection by the I&C technicians. The inspectors questioned the technicians concerning the operation of the equipment, the data being collected, and the installation of the test equipment. After the test was completed the inspectors obtained a copy of the data for this test, as well as, the previous test done on this ATTS. The inspectors reviewed the data and the technical requirements in the TS to verify that the test had been accomplished at the required frequency, and also, to verify that the test procedure met the intent of the testing requirements of TS.

Initially, the inspectors were unable to verify that the data being collected during the test met the TS requirements. This was due to the fact that the data being collected during the test was taken in electrical readings (milliamps), and the requirements in TS were expressed as pressures and temperatures. The inspectors questioned site engineering personnel concerning the relationship between the two. Based on the information provided, and a simple calculation performed by the inspector the relationship was established and verified as satisfactory. The inspectors concluded the technicians knowledge of the test process, procedures and data collected was very good. The inspectors also reviewed the information in the FSAR section 7.18 concerning these trip units.

3.1.6 34SV-E51-002-1S: RCIC Pump Operability

The test was performed to meet surveillance requirements 3.5.3.1 and 3.5.3.3 of the Unit 1 TS. The inspectors observed the operation of the equipment, and procedure adherence and data collection by the operators. The inspectors reviewed the test data and verified the TS requirements were met. The inspector also reviewed the information in the FSAR section 4.7, concerning the RCIC system.

3.2 Plant Re-engineering and Performance Team Implementation.

On or about January 8, the licensee implemented a new "Performance Team" concept for maintenance, planning and control and building and grounds activities to improve productivity, and efficiency. The re-engineering planning effort has been ongoing for about a year and some teams have been in place for some time. The new concept resulted in a total of seven performance teams. The Maintenance Manager's title became the Performance Team Manager. An assistant performance team manager and support staff were identified. The teams have assigned plant equipment and areas of responsibilities and will be responsible for the performance of their systems and material conditions of their areas. The team titles and areas of responsibilities are as follows: Team 1, Cooling Tower; Team 2, I&C/Surveillance; Team 3, Auxiliary Systems; Team 4, HVAC and Turbine; Team 5, Intake and EDG; Team 6, Refueling Floor; and Team 7, Facility Maintenance. Each team has a team leader and assistant team leader. The teams are designed to be self-sufficient. The teams consist of various crafts such as mechanics, electricians, I&C technicians, utility men, operators, engineering and technical specialists. HP personnel were assigned to some teams. A team will plan, help schedule and execute work. Teams will be responsible for budgeting work activities, manpower and resource scheduling and identification of training needs.

In addition to the performance teams, five teams were designated as shift teams. The shift teams are similar to the performance teams but work rotating shifts.

Central scheduling will coordinate and schedule activities with various performance teams. They will maintain the repetitive task schedule for PM's and surveillances. Plant dispatchers will be the contact point for identified plant problems. As problems are identified dispatchers will either dispatch the fix it now (FIN) team for further investigation and or repair or assign the problem to one of the performance teams for planning.

Licensee management informed the inspectors that a slight decline in maintenance tasks efficiency had been observed. However, they believed this would be short lived until the personnel became more familiar with the re-engineering metholodogy.

The inspectors did not observe any decline in maintenance scheduling or work activities that affected safety related equipment performance or availability.

3.3 Inspection of Open Items

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

3.3.1 (Closed) VIO 50-321/94-31-01: Inadequate Procedure For Fabricating Rigging Slings During Refuel Floor Activities.

The inspectors reviewed the licensee's submittal, dated March 2, 1995. The licensee's corrective actions included the following: The plant General Manager issued a letter, dated January 24, 1995, prohibiting the on-site fabricating of rigging slings. Should a need to fabricate rigging slings arise, special permission, procedures, training, and personnel qualification requirements would be implemented. The inspectors periodically observed rigging slings and did not observe any on-site fabricated rigging slings. Based upon the inspectors review of licensee's actions, this item is closed.

3.3.2 (Closed) IFI 50-321,366/95-16-02: Switchyard Equipment Failures Resulting in Plant Transients.

Several switchyard equipment failures had occurred that resulted in plant transients. Electrical ground failures of the transformer cooling fans were identified as the main cause by the licensee's ERT. On more than one occasion, the ground fault cascaded to in-plant electrical boards and caused the 600 Volt buses to trip. These trips created the plant transient. In addition, the ground faults generate transient voltages and electromagnetic interferences that caused the solid state trip units, Type RMS-9, in the AK-type circuit breakers to false trip.

The inspectors reviewed the documentation and reports provided by the ERT that identified the problems and recommended corrective action. The licensee was in the process of completing the replacement of all the transformer fans superior type motors. In addition, the licensee's staff recognized the need to suppress the voltage transients that cause the RMS-9 trip unit to false trip. Filters and suppressor are scheduled for installation in the upcoming outage. The inspector concluded the ERT had determined the problems and appropriate corrective action was being implemented. Based upon the inspector's review of the licensee's actions, this IFI is closed.

3.3.3 (Open) IFI 50-321,366/95-27-01: Recurring EHC Servo Filter Plugging Causing Scram.

This IFI addressed recurring EHC servo filter plugging that caused a recent reactor scram and other main turbine valve problems. An ERT was initiated to investigate the problem and make recommendations for corrective actions.

The inspectors discussed the findings with the ERT concerning the contamination found on the filters. At that time, the ERT discovered the contamination was in both units instead of just Unit 1. The ERT informed the inspectors this problem will require further evaluation to resolve. The inspectors concluded the ERT was in the process of doing all that could be expected under the circumstances. This IFI will remain open.

The maintenance activities observed were performed in a professional manner and the areas examined were well maintained.

No violations or deviations were identified.

4.0 Engineering Activities (37550) (37551) (92903) (92700) (37828)

On-site engineering activities were reviewed to determine their effectiveness in preventing, identifying and resolving safety issues, events and problems.

4.1 Design Change Control Processes

The inspectors reviewed the design change program, the engineering backlog, and audits of the design change program. The inspectors reviewed the current revisions of the procedures listed below which control design changes and verified that the design control measures were consistent with 10 CFR 50, Appendix B, Criterion III. The following procedures were reviewed:

40AC-ENG-003-0S: Design Control
40AC-ENG-018-0S: Temporary Modification Control
42EN-ENG-029-0S: Minor Design Change
42EN-ENG-008-0S: Test or Experiment Request
17MS-MMS-003-0S: As-Built Notices
17MS-MMS-002-0S: DCR Processing.

From review of the above procedures the inspectors concluded that the following attributes were adequately addressed: design processes, design inputs, interface controls, design verification, document control, post-modification testing, control of field changes, and 10 CFR 50.59 safety evaluations. The inspectors concluded that adequate controls were in place to ensure effective implementation of design changes.

4.2 Review of Engineering Backlog

The inspectors reviewed the backlog of items in the Engineering Support Group. These items included DCRs, temporary modifications, minor design changes, requests for engineering review, and open engineering action items. The majority of the items in the backlog were opened less than one year ago. The items opened prior to 1995 involve lower priority issues. The overall number of items in the backlog was reasonable. None of the open items affects equipment or system operability.

The inspectors concluded that the licensee was effectively managing their engineering workload and completing engineering work activities in a timely manner.

4.3 Quality Assurance Assessment and Oversight

The SAER group performs routine audits of engineering performance. The inspectors reviewed two special audits performed in 1995 of engineering activities. These were Audit Numbers 95-SA-2, Minor Design Changes, and 95-SA-7, The Power Uprate Program. No findings were identified in Audit 95-SA-7. Two findings were identified in Audit 95-SA-2. These included several examples of procedural noncompliance in implementation of the minor design change program regarding independent design verification and a personnel error regarding failure to perform post-modification testing after implementation of a modification. The licensee revised their minor design change procedure, 42EN-ENG-029-OS, to clarify the requirements for independent design verification and performed the required post-modification test in response to the audit findings.

The inspectors concluded that the audits of engineering activities were effective in identifying engineering performance deficiencies and were useful in providing oversight to management. Corrective actions in response to the audit findings were acceptable.

4.3.1 Licensee's Controls and Self-assessment Programs

The inspectors reviewed audit number 95-SA-7, Power Up-Rate, which documented the results of the licensee's self-assessment of Unit 2 Power Up-Rate Program. The audits focused primarily on the DCRs that implemented the required changes and on the test program that assured the changes had no adverse effects on plant safety.

Based on the results of this review the inspectors concluded that the licensee had effectively implemented the requirements of 10 CFR 50 Appendix B, Criterion 18, Audits. The scope and depth of the activities reviewed were comprehensive. Additionally, the results demonstrated good engineering technical support for Unit 2 Power Up-Rate Program. Audit report 95-SA-7 was determined to be a quality product.

4.3.2 Review of Engineering Support and Control Audit Reports

The inspectors reviewed audit reports performed by the SAER group onsite auditors for engineering activities to determine if the audit program had been implemented adequately. FSAR Chapter 17, Section 2.18, was reviewed by the inspectors for the verification of the audit requirements. The purpose of these audits as stated in the FSAR was to verify that engineering activities complied with the QA program, license requirements, Technical Specifications, and the applicable regulations. One onsite audit responsibility listed in the FSAR was to audit "design changes and plant modification control".

The inspectors reviewed the procedure used by the licensee auditors, Procedure SAER-07, Safety Audit and Engineering Review for SAER Audits and selected the following audit reports for review:

- 94-E&T-1, Audit of Engineering and Technical Support
- 94-E&T-2, Audit of the Engineering and Technical Support Organizations
- 94-PC-1, Audit of the Procedure Control Program
- 95-SA-2, Audit of Minor Design Changes

The above audits covered and evaluated a broad scope in the engineering and plant support areas such as the check valve, relief valve, and erosion/corrosion programs, trending, equipment qualification, outage and planning, maintenance engineering and other technical activities. Five findings were identified as the result of these audits. The inspectors reviewed the audit reports, the findings, and the corrective actions. The corrective actions included revisions to procedures, field modifications, and training of personnel in recurrence control.

The inspectors concluded that the audits of engineering activities were effective in identifying engineering performance deficiencies, and were useful in providing valuable information and trend direction to management. Corrective actions in response to the audit findings were adequate and effectively implemented. The auditors were knowledgeable and skillful to perform the audits and identify the problems.

4.4 Engineering Response to Emergent Issues

The inspectors discussed with engineering supervisors the methods used within the Engineering Support Group for handling emergent issues which arise during day-to-day plant operations. These discussions disclosed that the normal point of contact in engineering for operations or maintenance personnel when an operational problem or deficiency occurs is with the responsible system engineer who then obtains any additional engineering assistance necessary to resolve the issue. The response time to various issues is dependent on the type and seriousness of the problem. However, most issues are handled by a telephone request for assistance. Response to issues is not delayed pending receipt of formal written requests for assistance. When problems occur outside of normal business hours, engineering assistance is requested through the "duty" engineer who is on call 24 hours per day to respond to emergent issues.

The inspectors concluded the licensee's system for responding to engineering issues was effective. No examples were identified where resolution of problems was delayed by lack of response from engineering personnel.

4.5 Modifications

The inspectors continued to review and observe the ongoing modification activities. The inspectors reviewed DCR and MDC packages and observed implementation activities. These reviews included 10 CFR 50.59 reviews, unreviewed safety question criteria, required testing and job task activities. The observed work included work process procedures, installation activities and required testing activities. Among the DCRs reviewed and installation activities observed were:

DCR 94-16:	Unit 2 Drywell Steel
DCR 95-17:	Diesel Generator 1A Replacement
MDC 95-5003:	Add Stiffener to A/C Unit Frame
MDC 95-5020:	Drywell Sand Cushion Drain
DCR 95-19:	CRD Platform Extension

The inspectors verified that the 10 CFR 50.59 safety evaluations were adequate, verified that the modifications were reviewed and approved in accordance with the licensee's procedural requirements, that applicable design bases were considered, and that appropriate post-modification testing requirements were specified. The inspector also verified that work instructions, including drawings and specifications, were adequate to implement the modification.

The inspectors also observed work in progress to implement DCR 95-17: Diesel Generator 1A Replacement. The work completed to date included installation of scaffolding and drilling holes in the reinforced concrete roof slab for installation of temporary supports.

The inspectors concluded that the DCRs and MDCs reviewed were being implemented in accordance with the licensee's design change procedures and requirements.

A temporary shielding request for shielding around the entrance of the control room kitchen area was reviewed. The inspectors also examined the temporary installed shielding. The inspectors observed that an engineering evaluation had been completed which showed the loads from the temporary shielding did not exceed the allowable design values. The inspectors also observed that the area affected by the temporary shielding was non-safety related. Safety related equipment was not in close proximity of the temporary shielding.

The inspectors concluded from their review of temporary shielding that a seismic loading or operability concern did not exist.

4.5.1 Review of Electrical Modifications

The inspectors reviewed the following DCRs to verify technical adequacy and compliance with the requirements of the ANSI N45.2.11-1974 design control program.

DCR No. 91-12, Unit 1 Class 1E Transformers Retrofill

DCR No. 91-123, Replace Eagle Timers

DCR No. 95-17, Replace 1A Emergency Diesel Generator

DCR No. 95-35, Pull and Terminate Parallel Cable From Turbine Building Switchgear to EDG Building MCC.

Based on the above reviews the inspectors concluded that the DCRs were technically adequate and complied with the design control program with the following exception. Review of "Specification for Generator Replacement for Plant Hatch-Units 1 and 2 Diesel Generators Purchase Order No. 6020924" for DCR 95-17, revealed that Section 2.1.1, Codes and Standards, had been revised by Addendums 1 and 2 to delete IEEE 344; IEEE 323; ANSI N45.2.13-1976; and Regulatory Guide 1.100.

On February 22, 1996, the inspectors and NRC management met with licensee's engineering personnel to discuss this issue and to verify that adequate technical and quality requirements had been incorporated in the procurement document for purchase of the replacement EDG referenced in DCR No. 95-17. The licensee stated that seismic qualification for the replacement EDG would be performed in accordance with the guidance delineated in the GIPs which had earlier been submitted to NRR for their approval. As a member of SQUG, the licensee had responded to Generic Letter 87-02, Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue A-46, and submitted the GIPs to NRR for revising the licensing basis of Unit 1 with regard to seismic qualification. Licensee's personnel concurred with the inspectors observation that the methodology for seismic qualification delineated in HNP-1-FSAR-8, Section 8.4.4, does not accurately describe the seismic qualification procedure for the replacement generator. The FSAR will be revised to delete these requirements upon approval of the GIPs by NRR.

Deletion of ANSI N45.2.13-1976, Quality Assurance Requirements for Control of Procurement Items and Services for Nuclear Plants, was discussed in the meeting conducted February 22, 1996. The licensee's position was that inclusion of this standard in section 2.1.1 was an error and the requirements delineated in this standard was never intended to be imposed by the purchaser on the vendor. The requirements are imposed on the purchaser's QA program only, and verification of the vendor's 10 CFR 50 Appendix B QA program implementation was performed via audits. The inspector's concern with the deletion of these standards from section 2.1.1 of the procurement specification was discussed with the licensee.

Specific non-compliance with commitments delineated in the FSAR caused by these deletions are identified below:

> HNP-1-FSAR-8, Section 8.4.4, Safety Evaluation, Revision 8. Describes dynamic analysis of the diesel generators by the vendor for seismic qualification per IEEE 344-1971
>
> HNP-2-FSAR-17, Section 17.2.4, Procurement Document Control. Technical and quality requirements to be imposed on vendors are included on procurement documents according to the procurement level established.
>
> HNP-2-FSAR-A, Section A.33- Quality Assurance Program Requirements (Operation) Conformance (Revision 2, 1978) Georgia Power Company has committed to the requirements of ANSI N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants.

The first paragraph of Section 5.2.7 of ANSI N45.2.13-1976, Maintenance and Modification, addresses those technical requirements to be applied during maintenance and modifications. The first sentence of this paragraph is intended to mean that the technical requirements associated with maintenance and modifications can be the original requirements or better.

The fourth paragraph of Section 5.2.7 of ANSI N45.2.13-1976, addresses QA programmatic/administrative requirements associated with maintenance and modifications (including replacements). This paragraph is intended to mean that QA programmatic/administrative requirements contained in ANSI N18.7-1976, including referenced standards, shall apply to those maintenance and modification activities even though such requirements were not in effect originally.

Regulatory Guide 1.123, Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants endorses ANSI N 45.2.13-1976, Quality Assurance Requirements for Control of Procurement Items and Services for Nuclear Power Plants, to which the licensee is committed. Regulatory position C.5 states that the ANSI N45.2.13-1976 does not provide requirements specific to spare and replacement parts. Section 5.2.13 of ANSI N18.7-1976 addresses control of spare and replacement parts during the operations phase of nuclear power plants. The provisions of Section 5.2.13 of ANSI N18.7-1976 related to control of spare and replacement parts are considered applicable and should be used with the provisions of ANSI N45.2.13-1976.

Pending additional NRC review, deletion of ANSI N45.2.13-1976 from section 2.1.1 of the procurement specification was identified as URI 50-321/96-02-01, Deletion Of Quality Requirements From Specification For Procurement of Replacement EDG.

4.5.2 Transformer Modifications

DCR No. 91-12 changed the di-electric fluid in the following 600 volt, class 1E transformers:

(1R23-S003) Station service transformer 1C

(1R23-S004) Station service transformer 1D

(S11-S007) Station service transformer 1CD

The transformers will be retrofilled with silicone and derated 15% to compensate for the difference in thermal properties between silicone and askarel. The inspectors reviewed FSAR section 8.3.5, dated July, 1994, and verified that the FSAR had not been revised to incorporate the new transformer OA/FA rating of 1190/1368 KVA. A FSAR change request was included in the DCR to ensure revision of the FSAR upon implementation of the plant modification. Additional reviews of the DCR revealed that an electrical calculation which demonstrated the capability of the derated transformers to carry the connected load had not been referenced in the DCR. This issue was discussed with licensee's personnel on February 22. The inspectors were provided with calculation No. SENH 89-009, Steady State Loading Emergency Buses 1E, 1F, and 1G During a LOCA/LOSP/SBO Event, which was intended to support the technical adequacy of DCR No. 91-12. Based on review of this calculation the inspectors concluded that, when energized from the on-site emergency electrical power system there was adequate margin between the transformer OA/FA rating of 1190/1368 KVA and the running load of 995 KVA with a demand factor of 1.0.

In response to the inspector's request for information concerning the transformer KVA margin when the connected loads were fed from the off-site electrical power system, facsimile copies of calculation number 94752PG, Southern Company Services Station Auxiliary Design Program, were provided by the licensee on February 23, 1996. The inspectors reviewed this calculation for a LOCA/non-LOSP condition along with drawing worksheet S-91-012-E003, Revision A, Edwin I Hatch Nuclear Power Plant-Unit 1 & 2 Single Line Diagram, 600V Bus 1C, R23-S003, & Bus 1D, R23-S004. Based on this review the inspectors concluded that the calculation did not include all the loads connected to the 600V Bus 1C. Specifically, feeders for loads R42-S028, Battery Charger 1D, and R44-S001, Vital AC UPS System 75 KVA transformer had not been incorporated in the calculation. Apparently calculation number 94752PG had not been revised to correctly reflect all the connected loads on the 600V Bus 1C. Based on the demand factors used in this calculation for the connected loads, however, it appeared that calculation number SENH 89-009 was the bounding calculation for establishing the rating of the station service transformers. The maximum demand for the connected load when fed from the EDG was 955 KVA as compared to 638 KVA when fed from the off-site power supply. Inclusion of the loads omitted from the calculation increased the 638 KVA load to 756 KVA with a demand factor of unity for the added loads. In both instances the transformers OA/FA rating of 1190/1368 KVA has been demonstrated to be adequate for the connected load.

4.5.3 Calculation Review for Plant Modification

The inspectors reviewed calculation number SCNH-95-033, Modifications to Diesel Building Roof for Removal of Diesel Generator Stator 1A, Revision A. This calculation was generated to implement DCR 95-017 to qualify methods for a diesel building concrete roof cut-off and adding restraints to support the cut-off roof and a monorail. The new opening will enlarge an existing roof fan opening to allow removal of the diesel generator through this opening. The calculation was reviewed for completeness, accuracy, adherence to design criteria, and the FSAR, adherence to procedural requirements, and acceptability of calculation methods in accordance with industrial standards (codes) and good engineering practices. The inspectors considered the design calculation to be acceptable.

The cut-off roof slab will be 6 inches larger on the top, all around, than the bottom. Therefore, the cut-off roof slab can be returned to the original location as a concrete plug and to be removable by crane in the future. The cut-off concrete roof when returned will be tightened with through-bolts at two locations and supported by two steel beams. The steel beams will be extended beyond the cut-off concrete roof, supported by steel plates, and anchored to the concrete roof. The steel beams will also carry a monorail underneath the roof for moving equipment. The calculation contained the qualification for the through-bolts, beams, welds, plates, anchor bolts, and monorail loads. The inspectors verified the rebar strength, seismic coefficients, steel and concrete allowables, computation, weld size and allowables, the capacity and direction of the lift up lugs, monorail loads, plate sizes and thicknesses, etc. The inspectors concurred with the licensee conclusion that the proposed methods to cut and support the concrete roof for the removal and replacement of the diesel generator were adequate and acceptable.

Discussion with the licensee revealed that diesel generator replacement may entail temporarily storing the generator on top of the diesel generator building roof. However, the licensee had not conducted any evaluation for the contingency of placing the generator on top of the building roof or for the accidental drop of the generator on top of the roof. This evaluation was needed to address the potential damage to the building roof and equipment inside the building, and the impact on plant operation. The crane boom can swing 150', but the safe lift path was not developed. After discussion on the issue, the licensee stated that an evaluation of the crane lift and impact on plant safety would be performed before implementation of the lift operation.

4.6 Modification Installation and Testing

The inspectors documented in IR 50-321,366/95-27, a review of DCR 95-47, Install Series Conversion on the 1B EDG. The inspectors observed and reviewed the installation and testing of the DCR. The design change involved the replacement of the two turbocharger compressors and the engine driven positive displacement blower. The original air scavenging system used the blower as an air source, discharging air through the turbocharger, for starting and running at light loads. As engine output increased, turbocharger capacity would exceed blower volume and a flapper valve would open for additional air. This system was a blower-to-turbo series system for starting and light loads, and a blower-and-turbo parallel system for heavier loads.

The new installation results in longer engine life through decreased wear. During this major modification activity the licensee also performed the 18 month inspection and surveillance requirements on the engine and the alternator. The original schedule was for the tasks to be completed within four days. The guidance for on line maintenance was for the activities to be completed within one-half the RAS time frame. The RAS for the 1B EDG is seven days. During the post modification testing licensee personnel discovered that the pressure in cylinders 12 and 8 exceeded the manufacturers limits. The licensee was informed that the wrong inlet nozzles were installed in the turbo-chargers and correct parts were not readily available. As a result the original work activity schedule was extended.

The inspectors concluded from the reviews and observations that on line maintenance was generally scheduled, well controlled and completed in a timely manner based on past maintenance experience. The inspectors discussed with licensee management that similar detailed work knowledge and experience for on line major modifications may not be available to ensure timely completion of the modification. In this case the original work activity was extended from four days to approximately six days. However, the TS RAS was not exceeded.

4.7 Review of IN 96-07: Slow Five Percent Scram Insertion Times Caused by Viton Diaphragms in Scram Solenoid Pilot Valves.

The inspectors discussed this problem with licensee management and engineering personnel. The inspectors were informed that Unit 1 did not contain any ASCO scram solenoid pilot valves with Viton diaphragms. All valves on Unit 1 were Buna-N type diaphragms.

Unit 2 had 130 scram solenoid pilot valves that contain Viton diaphragms. These valves were installed during the fall 1995 refueling outage. The valves that were installed were second generation Viton valves with an expected 10 year EQ life.

The inspectors reviewed a sample of completed surveillance procedures for both Unit 1 and Unit 2 Control Rod Scram Testing. Procedures 42SV-C11-001-1S and 42SV-C11-001-2S, Revision 3 and 4 and later revision 0 which was a common unit procedure were reviewed. The test were completed in 1993, 1994 and 1995. The inspectors verified that the control rod scram times met Unit 2, TS 3.1.4, Control Rod Scram Times, acceptance criteria and no additional problems were identified.

Several NRC and vendor documents were issued describing potential problems with ASCO solenoid valves with Buna-N diaphragm material. The inspectors reviewed RICSIL 69, Scram Solenoid Pilot Valve Diaphragm Degradation, Revision 1, dated May 12, 1994. The inspectors also reviewed the licensees evaluation and corrective actions in response to the document. The RICSIL informed licensees that diaphragm kits or valve assemblies assembled after early 1989 may have a shorter service life than the 3 or 4 years service life recommended.

In response to the vendor recommendations, the licensee removed and inspected several valves from both units during the 1994 spring refueling outage. The diaphragms that were replaced had been in service for approximately 4.5 to 5 years and showed no degradation. The diaphragms that were replaced appeared to be identical to the new diaphragms. Also, the replaced diaphragms had no appearance of drying out, excessive hardening, or cracking. The licensees investigation in response to the vendor recommendations and past operating history did not identify any valve failures or problems. Additionally, the licensee completed an EQ evaluation for the valves and concluded that the service life could be extended from the recommended 3 or 4 years to 4.5 or 5 years.

The inspectors also reviewed several other documents and some of the licensee's actions concerning similar problems. These included RICSIL 69: Scram Solenoid Pilot Valve Diaphragm Degradation, Revision 2, dated October 12, 1994; NRC IN 94-71: Degradation of Scram Solenoid Pilot Valve Pressure and Exhaust Diaphragms, and SIL 586: Scram Solenoid Pilot Valve and Air System Maintenance, dated January 4, 1995.

The inspectors concluded that the licensee was well aware of the potential solenoid valve problem. Maintenance, onsite and offsite engineering as well as the vendor were actively involved in evaluating the potential problem. The inspectors concluded the licensees response and investigations with respect to the recommendations of the above documents were appropriate and timely. Their investigations were thorough and comprehensive. The licensees maintenance program requiring 1/3 replacement of the 274 valves every refueling outage was viewed as positive.

The inspectors also concluded that, based upon the licensees efforts in evaluating the potential problem and the favorable past valve operating history, that the ASCO solenoid valve diaphragm degradation problem identified at other sites was not a problem for the licensee. The inspectors reviewed both Unit 1 and Unit 2 FASR section 7.2 and concluded that scram time testing metholodogy was appropriate.

4.8 Inspection of Open Items

The followings previous inspection items were reviewed and closed.

4.8.1 (Closed) IFI 50-321/94-27-04: Resolution of Unit 1 EDG LOSP/LOCA Timer, LOSP/LOCA TD Relay Testing, and Endturn Inspection Problems.

This item was issued when a series of hardware deficiencies in electrical systems were identified. The licensee generated four DCRs to correct the problems. DCR 91-123 was to replace the Unit 1 LOCA/LOSP Eagle Timers on the 1A, 1B, and 1C EDGs with Agastat relays. These relays, augmented with type HFA and Struthers-Dunn relays, will perform the same primary safety function as the replaced Eagle Timer circuitry. A new automatic feature of the test circuitry provides a means of testing the relays during normal plant operations.

DCRs 95-07 and 08 were to add new class 1E time delay open and instantaneous relays to the RHR pump start logic. The function of the new relays will be to override a voltage transient caused by the initial starting of the CS and RHR pumps onto their respective EDG busses during a LOSP/LOCA. DCR 95-08 was installed and tested on Unit 2 during the Fall 1995 refueling outage. DCR 95-07 for Unit 1 is scheduled for completion during the spring refueling outage.

DCR 95-17 was to replace the existing 1A EDG with a like for like replacement. This will eliminate the concerns associated with internal winding cracks and movement and increase EDG reliability.

The inspectors reviewed the Unit 2 DCR work activities and operability testing. Deficiencies were not identified. The remaining DCR work activities are scheduled for completion during the Unit 1 spring 1996 refueling outage. Based on the inspectors review of completed work activities and testing, review of licensee's activities and scheduled work and issuance of the DCRs to correct the problem this item is closed.

4.8.2 (Closed) LER 50-366/95-09: Remote Shutdown Panel Found Degraded Due to Inadequate Testing and Design.

This LER was issued when deficient conditions on the Unit 2 RSDP were identified by the licensee in October and November, 1995. Several components could not be operated from the RSDP per design. Details of the deficiencies are documented in IR 50-321,366/95-26. The licensee took immediate and comprehensive corrective actions to correct the deficiencies. These actions were discussed during a predecisional enforcement conference held in the NRC Region II office on December 28, 1995. The NRC issued a NOV in correspondence dated January 19, 1996. Based upon the inspectors reviews of the licensee's actions and the issuance of a NOV, this LER is closed.

4.8.3 (Closed) LER 50-321/95-05: Ground on 600-Volt Bus Affects HPCI System and RPS.

This item was issued when an electrical ground in an elevator control circuit caused the 600 volt bus 1D nonessential loads to trip. The nonessential loads included the Division II battery charger which was declared inoperable. The supported systems included the HPCI which was also declared inoperable. The ground is believed to have produced a spurious trip of the RPS MG set breaker. The licensees corrective actions included supplying power to the elevator from a non-safety related load and installing a noise filter on the RPS MG set breaker to prevent similar occurrences. Based upon the inspectors review of the licensee's actions, this item is closed.

One URI was identified.

5.0 Plant Support Activities (71750) (84750) (92701) (82301)

Security, health physics and other plant support activities were routinely observed and monitored during the report period. These activities included plant security access controls, locked high radiation area doors, proper radiological posting, personnel frisking upon exiting the RCA, and status of various FP equipment. The observations and monitoring were performed in conjunction with the conduct of other inspection activities.

5.1 Radioactive Effluent Monitoring Instrumentation

TS 5.5.1 and 5.5.4.a for both units required the licensee to establish, implement, and maintain a program for the control of radioactive effluents. The program was required to be described in the ODCM, to be implemented by operating procedures, and to include limitations on the operability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests. Sections 2.1 and 3.1 of the ODCM required the instrumentation to be operable during specified operational conditions and demonstrated to be operable by the performance of channel checks, source checks, channel calibrations, and channel functional tests at specified frequencies. Compensatory measures for inoperable monitors were specified in action statements.

The inspector toured the main control room, the radwaste processing control rooms, and other relevant areas of the facility to locate and determine the current operational condition of the following effluent radiation monitors.

1D11-K604:	Unit 1 Liquid Radwaste Effluent Monitor
2D11-K604:	Unit 2 Liquid Radwaste Effluent Monitor
1D11-K619A & B:	Unit 1 Reactor Building Vent Noble Gas Activity Monitors
2D11-K636A & B:	Unit 2 Reactor Building Vent Noble Gas Activity Monitors
1D11-K600A & B:	Main Stack Noble Gas Activity Monitors

The above selected monitors were found to be operable at the time of the tour except for the Unit 1 liquid radwaste discharge monitor which had been declared inoperable due to erratic spiking of the measured count rate. The radwaste control room operator scrolled the monitors's chart recorder through the previous 5 days to demonstrate for the inspector when the erratic spiking started and that the erratic behavior was occurring both during and between permitted releases. The inspector noted from the information recorded on the out-of-service tag posted on the monitor's display panel that a work request had been promptly issued for repairing the instrument.

The inspector reviewed the procedures listed below which related to the performance and documentation of channel checks, source checks, channel calibrations, and channel functional tests for the above listed monitors.

34SV-SUV-019-1S:	Surveillance Checks
34SV-SUV-019-2S:	Surveillance Checks
57SV-CAL-015-0S:	Process Radiation Monitor Calibration
57SV-D11-010-1S:	Main Stack Radiation Monitor Functional Test and Calibration Check (FT&C)
57SV-D11-011-1S:	Liquid Radwaste Effluent Radiation Monitor FT&C
57SV-D11-011-2S:	Liquid Radwaste Effluent Radiation Monitor FT&C
57SV-D11-021-1S:	Reactor Building Vent Radiation Monitor Channel Functional Test and Calibration
57SV-D11-022-2S:	Reactor Building Vent Radiation Monitor FT&C
62CI-CAL-007-0S:	Off Gas Vent Pipe (Stack) Monitor and Post Treatment Monitor
62CI-CAL-011-0S:	Reactor Building Radiation Monitor
64CI-OCB-009-0S:	Liquid Radwaste Radiation Monitoring

The inspector determined that the above procedures included provisions for performing the required surveillances in accordance with the relevant sections of the ODCM and at the specified frequencies. The inspector also reviewed selected licensee records of channel checks, source checks, channel calibrations, and channel functional tests for each of the above listed monitors. The records selected for review were generally the two most recently completed data packages for the above surveillances. Those records indicated that the surveillances had been performed in accordance with their applicable procedure and at the required frequency.

Based on the above reviews and observations, it was concluded that the licensee had effectively implemented a program for maintaining radioactive effluent monitoring instrumentation in an operable condition and for performing the required surveillances to demonstrate their operability.

5.2 Control Room Emergency Ventilation Systems

TSs 3.7.4 and 5.5.7 for both units described the operational and surveillance requirements for the MCREC. Two independent air treatment systems were required to be operable during reactor startup, power operation, hot shutdown, and refueling operations. Action statements applicable to various modes were provided for conditions in which one or both of the systems were inoperable. The frequencies for functional testing, visual inspection, filter leak testing, air flow measurements, differential pressure measurements, and charcoal adsorption efficiency testing were specified.

The inspector toured the mechanical equipment room in which the control room ventilation systems were located and observed that the components and associated ductwork were well maintained structurally. No physical deterioration of the ductwork sealants was evident.

The inspector reviewed the procedures listed below and determined that they included provisions for performing the above operability and performance tests at the required frequencies. The acceptance criteria for the test results specified in those procedures were consistent with the TS requirements. Review of selected records of those tests indicated that they had been performed at the required frequencies and that the acceptance criteria had been met.

34SV-Z41-001-OS: Control Room Filter Train Operability
42SV-Z41-001-OS: Main Control Room Pressurization Logic System Functional Test
42SV-Z41-002-OS: Testing of Control Room Habitability Filter Trains
42SV-Z41-003-OS: Control Room Filter Train Flow and DP Measurement

Based on the above reviews and observations, it was concluded that the licensee had complied with the above operational and surveillance requirements for the control room emergency ventilation systems.

5.3 Emergency Preparedness Exercise

On January 31, the inspectors participated in a licensee practice EP exercise. Particular attention was directed to the TSC activities for analysis of plant conditions, and recommended actions for accident mitigation. The EP scenario challenged operators and the EP participants to the extent that an Alert, SAE, and GE were declared. The inspectors concluded that staffing and activation of the TSC, OSC and EOF were timely. The inspectors concluded that the TSC staff members were effective in analysis of plant conditions and corrective action recommendations. A site evacuation was correctly declared. Personnel accountability was completed within the 30 minute requirement.

Licensee evaluators concluded that one objective, to "demonstrate the ability to identify initiating conditions, determine Emergency Action Level parameters and correctly classify the emergency through the exercise", was not met. The inspectors discussed operator performance that resulted in unsatisfactory completion of the objective with licensee management. The inspectors were informed that the simulated initiating event was classified as a NOUE for loss of offsite power instead of an Alert for an aircraft crash onsite that resulted in the loss of offsite power. The licensee identified other minor areas for improvement.

The inspectors concluded that licensee performance during the practice EP exercise was very good. Significant deficiencies were not identified.

5.4 Inspection of Open Items

(Open) IFI 50-321,366/95-05-01: PASS Program Enhancements- Installation of New Valves, Consolidation of Procedures, and Revision of the FSAR.

During the inspection conducted on February 14-18, 1994, it was found that the PASS in-line measurement equipment used to analyze reactor coolant for boron concentration, chloride concentration, PH, and conductivity had been out of service for approximately two years. Details of this problem are documented in IR 50-321,366/94-06. It was also found that the licensee's training program included provisions for initial training of PASS operators but did not include provisions for refresher training. Followup inspections to review the licensee's actions for improved performance in the PASS program were conducted on November 28 - December 2, 1994, and February 27 - March 3, 1995. Details of the followup inspections are documented in IRs 50-321,366/94-30, and 95-05. During the latter followup inspection the licensee indicated that a DCR was being processed for the replacement of some currently used valves with new valves of improved design. That modification was planned for mid-1995. The licensee also indicated that several of their procedures for operation of the PASS equipment were being consolidated, i.e., the separate procedures for obtaining diluted and undiluted samples will be combined. The FSAR was also being revised to reflect the current post-accident sampling and analysis methods and capabilities.

During this inspection it was determined that the procedures for operation of the PASS equipment had been consolidated from 12 to 5 procedures. The inspector also determined that DCR No. 95-010 had been approved on October 26, 1995, for installation of the new valves and for making other improvements to the PASS equipment. Seven MWOs had been issued for that work and, at the time of this inspection, were under review by the Maintenance and the Quality Control groups. The licensee indicated that the target completion date for this work was May 1996. The inspectors reviewed the applicable section of the FSAR with respect to the PASS system.

The licensee's records for FSAR Change No. 14B-011 indicated that the changes to PASS sampling and analytical methods had been approved by the Plant Review Board on January 11, 1996, and were under review by the licensee's corporate office. The licensee anticipated that the FSAR change would be submitted to the NRC within 4 to 6 weeks. This item will remain open pending installation of new valves in the PASS.

No violations or deviations were identified.

6.0 Other NRC Personnel On Site

On January 29 and 30, the NRC Branch Chief, Mr. P. H. Skinner visited the site. Mr. Skinner met with the resident inspector staff to discuss plant status and current issues. He toured the plant, attended a managers plant status meeting and reviewed licensee documents.

7.0 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description.

During a portion of the inspection period, February 1 - 17, 1996, the inspectors reviewed the applicable sections of the UFSAR that related to the inspection areas discussed in this report. The following inconsistencies were noted between the wording of the UFSAR and the plant practices, procedures, and/or parameters observed by the inspectors.

HNP-1-FSAR-8, Section 8.4.4, Safety Evaluation, describes a method for seismic qualification of safety related equipment.

HNP-2-FSAR-17, Section 17.2.4, Procurement Document Control, describes the licensee's commitment for including technical and quality requirements to be imposed on vendors in procurement documents.

HNP-2-FSAR-A, Section A.33-Quality Assurance Program Requirements (Operation) Conformance (Revision 2, 1978) describes the licensee's commitment to implement the requirements of ANSI N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants and ANSI N45.2.13-1976, Quality Assurance Requirements for Control of Procurement Items and Services for Nuclear Power Plants (paragraph 4.5.1).

8.0 Exit

The inspection scope and findings were summarized on February 26, 1996, by Mr. B. L. Holbrook, with those persons indicated by an asterisk in paragraph 1. Interim exits were conducted on January 12, 19, and February 16, 1996. The inspector described the areas inspected and discussed in detail the inspection results. A listing of inspection findings is provided. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Type	Item Number	Status	Description and Reference
VIO	50-321/94-27-01	Closed	Failure to Follow Procedure During Unit 1 Refueling Activities (paragraph 2.4.1).
VIO	50-321,366/94-27-02	Closed	Inadequate Corrective Actions Regarding Fuel Movement Errors (paragraph 2.4.2).
IFI	50-321/94-27-04	Closed	Resolution of Unit 1EDG LOSP/LOCA Timer, LOSP/LOCA TD Relay Testing, and Endturn Inspection Problems (paragraph 4.8.1).
VIO	50-321/94-31-01	Closed	Inadequate Procedure For Fabricating Rigging Slings During Refuel Floor Activities (paragraph 3.3.1).

IFI	50-321,366/95-16-02	Closed	Switchyard Equipment Failures Resulting in Plant Transients (paragraph 3.3.2).
IFI	50-321,366/95-27-01	Open	Recurring EHC SERVO Filter Plugging Causing Scram (paragraph 3.3.3)
URI	50-321/96-02-01	Open	Deletion of Quality Requirements From Specification For Procurement of Replacement EDG (paragraph 4.5.1).
LER	50-366/95-09	Closed	Remote Shutdown Panel Found Degraded Due to Inadequate Testing and Design (paragraph 4.8.2).
LER	50-321/95-05	Closed	Ground on 600-Volt Bus Affects HPCI System and RPS (paragraph 4.8.3).

9.0 Acronyms

AC - Alternating Current
ANSI - American National Standards Institute
ASCO - Automatic Switch Company
ATTS - Analog Transmitter Trip System
BOP - Balance of Plant
CFR - Code of Federal Regulations
CR - Control Room
CRD - Control Rod Drive
CS - Core Spray
DC - Deficiency Card
DCR - Design Change Request
DPM - Disintegrations per Minute
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EHC - Electro Hydraulic Control
EOF - Emergency Operating Facility
EP - Emergency Preparedness
EQ - Environmental Qualification
ERT - Event Review Team
ESF - Engineered Safety Feature
ETR - Engineering Test Reactor
FIN - Fix It Now
FPP - Fire Protection Program
FP - Fire Protection

FSAR - Final Safety Analysis Report
FW - Feedwater
GE - General Emergency
GIP - Generic Implementation Procedure
HP - Health Physics
HPCI - High Pressure Coolant Injection
HVAC - Heating, Ventilation, and Air Conditioning
I&C - Instrumentation and Controls
IEEE - Institute of Electrical and Electronics Engineers
IFI - Inspector Follow-up Item
IN - Information Notice
IR - Inspection Report
KVA - Kilovolt Amperes
KVAR - Kilovolt Amperes Reactive
KW - Kilowatts
LER - Licensee Event Report
LOCA - Loss of Cooling Accident
LOSP - Loss of Site Power
MCC - Motor Control Center
MCREC- Main Control Room Environmental Control Systems
MDC - Minor Design Change
MG - Motor Generator
M&TE - Measurement and Test Equipment
Mwe - Megawatts Electric
MWT - Megawatts Thermal
MWO - Maintenance Work Order
NCV - Non-Cited Violation
NFPA - National Fire Protection Association
NOUE - Notice of Unusual Event
NOV - Notice of Violation
NRC - Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation
NSAC - Nuclear Safety and Compliance
NUE - Notice of Unusual Event
OA/FA- Oil Air/Forced Air
ODCM - Offsite Dose Calculation Manual
OSC - Operations Support Center
PASS - Post Accident Sampling System
PCIS - Primary Containment Isolation System
PDR - Public Document Room
PM - Preventive Maintenance Activities
PMMS - Plant Maintenance and Modification Support
PSW - Plant Service Water System
RCA - Radiological Control Area
QA - Quality Assurance
QC - Quality Control
RAS - Required Action Statement
RCIC - Reactor Core Isolation Cooling
RFPT - Reactor Feedwater Pump Turbine
RHR - Residual Heat Removal
RICSIL- Rapid Information Communication Services Information Letter

RMS - Radiological Monitoring System
RPS - Reactor Protection System
RT - Repair Tag
RTP - Rated Thermal Power
SA - Safety Analysis
SAE - Site Area Emergency
SAER - Safety Audit and Engineering Review
SBO - Station Black Out
SFP - Spent Fuel Pool
SNC - Southern Nuclear Company
SOR - Significant Occurrence Report
SPDS - Safety Parameter Display System
SQUG - Seismic Qualification Utility Group
SRO - Senior Reactor Operator
TD - Time Delay
TSC - Technical Support Center
TS - Technical Specifications
UFSAR- Updated Final Safety Analysis Report
UPS - Uninterruptable Power Supply
URI - Unresolved Item
VIO - Violation