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

Report Nos.: 50-321/92-08 and 50-366/92-08

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 Station Units 1 and 2

Inspection Conducted: March 15 - April 18, 1992

Inspectors: Scott E. Sparks for 4/30/92
Leonard D. Wert, Jr., Sr. Resident Inspector Date Signed

Scott E. Sparks for 4/30/92
Randall A. Musser, Resident Inspector Date Signed

Approved by: Pierce H. Skinner 4/30/92
Pierce H. Skinner, Chief, Project Section 3B Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, announced inspection involved inspection on-site in the areas of operations, including a Unit 1 scram and review of several failures to enter action statements during equipment inoperability, surveillance testing, maintenance activities, including an instance of diesel generator inoperability due to personnel error, review of design control deficiencies involving motor operated thermal overload bypasses, and review of open items.

A local officials meeting was held with the Appling County Board of Commissioners.

Results: During this inspection period, two violations were cited.

The first violation addressed two examples of design control deficiencies. Drawings did not accurately indicate the status of safety related MOV thermal overload bypasses. The thermal overload functions of several valves which should have been bypassed were not. The second example addressed incorrect values of elevations for level switch setpoints in the Instrument Setpoint Index document. (Violation 50-321,366/92-08-01: Inadequate Design Control Resulting in Incorrect Documentation and Configuration, paragraph 5.)

The second violation involved a failure to follow procedure. A failure to adhere to maintenance procedures resulted in the inadvertent inoperability of an emergency diesel generator. (Violation 50-366/92-08-02: Inadequate Component Identification During Maintenance Activities, paragraph 4b.)

The inspectors reviewed several instances in which TS LCO action statements were not entered during equipment inoperability periods. No violations of the TS action statements were noted. Some examples indicated improvements are needed in the licensee's practices involving equipment inoperabilities during surveillance testing. (paragraph 2c)

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
*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

NRC management/officials on site during inspection period:

P. Skinner, Chief, Reactor Projects Section 3B, Region II

*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 March 28, 1992, at 5:32 a.m., Unit 1 scrammed from rated power on low reactor water level. The scram is discussed further in paragraph 2b below. After repairing a drywell sump recirculation valve, control rod withdrawal commenced at 1:01 p.m., on March 30. The unit achieved criticality at 7:35 p.m. On March 31, at 12:49 p.m., the unit was tied to the grid. However, at 1:25 p.m., the unit was removed from the line due to a main transformer alarm which indicated the presence of combustion gases. Samples taken from the transformer indicated that no combustion gases were present. The sensor for the combustion gases was repaired. At 8:11 p.m., the unit was again tied to the grid and power ascension commenced. The unit reached rated thermal power on April 1, at 2:25 p.m., and remained at power for the remainder of the reporting period.

Unit 2 operated at power for the entire reporting period. As discussed in a previous inspection report (50-321,366/92-02), the licensee is continuing to monitor a small fuel leak discovered earlier in the cycle. The offgas pre-treatment levels are slowly increasing and are projected to increase for the remainder of the cycle which is scheduled to end in September 1992. Licensee management is considering an outage (of approximately 3 weeks in duration) to replace the failed fuel element(s). A flux t[illegible] performed in February 1992, determined that the failed fuel [illegible] were located in the vicinity of control rod 30-19. The residents are monitoring the licensees activities associated with this condition.

In addition, as discussed in inspection report 50-321,366/92-05, the residents are continuing to closely monitor leakage past the HPCI pump discharge valve (2E41-F006) for further degradation.

The inspectors reviewed plant operations throughout the reporting period to verify conformance with regulatory requirements, Technical Specifications, 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, and nuclear safety and compliance 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. 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.

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-OS, "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- perated 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.

On March 18, one of the inspectors attended portions of a meeting between the licensee's EP representatives and several county emergency management directors. The meeting was held at the Toombs County EOC. In addition to meeting with several of the local EMA representatives, the inspector toured the EOC facilities. The inspector noted that a close working relationship exists between the involved emergency directors and the licensee EP group.

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

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

During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed.

On March 19, one of the inspectors participated in an unannounced emergency planning activation drill conducted by the licensee. The drill involved a hydrogen tank truck incident and a loss of protected area security boundaries. The inspector observed that fire brigade response to the scene was prompt and the incident was properly classified. With the exception of some problems involving initial offsite notifications (which were apparently caused by drill/simulation issues), the response to the simulated emergency was appropriate.

On April 1, C. T. Moore returned to his position as Assistant General Manager - Plant Support after successful completion of SRO license qualification training.

b. Unit 1 Reactor Scram on Low Water Level

On March 28, 1992, at 5:32 a.m., Unit 1 scrammed from rated power on low reactor water level. The transient began when the Unit 1 shift supervisor mistakenly opened the supply breaker to the 600 V Bus 1B, causing a momentary loss of control power to the reactor feedwater pumps. The shift supervisor believed he was opening the supply breaker to the 1AB transformer (a 4160/600 V transformer which is the alternate source of power to 1A and 1B 600 V busses) to prevent personnel injury from occurring as maintenance personnel were in the process of moving the supply breaker from the 1C 4160 V bus to the 1D 4160 V bus. In actuality, the moving of the supply breaker was completed by 5:20 a.m. and was in its designated location and in the open position.

As a result of the loss of the 600 V 1B bus, the reactor feedwater pumps began to decrease in speed and a decrease in reactor water level occurred. Within one to two seconds after the 600 V bus 1B was lost, control power was restored to the reactor feedwater pumps. The control system responded and began to increase reactor water level at a rapid rate. The operator monitoring the feedwater system believed that this rapid feedwater rate would cause a high level turbine/feedpump trip and therefore took manual control of the reactor feedwater pumps. Reactor water level increased to within approximately one inch of the high level trip and then began a rapid decrease. The operator was unable to maintain reactor water level above the scram setpoint and the reactor tripped on low level. Reactor level decreased to a minimum of -12 inches (-162 inches being the top of active fuel). Level was recovered with the feedwater system and pressure was controlled automatically by the EHC system via the main turbine bypass valves. In addition to the RPS actuation (on low water level), a PCIS Group 2 isolation occurred as designed at a reactor water level of 12 inches. No ECCS actuations occurred nor were any required for vessel level recovery (RWL did not reach the HPCI/RCIC initiation setpoint).

Following the reactor scram, the licensee de-inerted the drywell to perform repairs on a malfunctioning drywell sump recirculation valve. Reactor startup commenced on March 30, 1992 with the unit reaching rated thermal power on April 1. The residents will continue to track the licensee's corrective actions on this occurrence via the forthcoming LER.

c. Failures to Enter TS LCO Action Statements During Equipment Inoperability

During the report period, several instances were noted in which TS LCOs were not entered despite equipment operability questions.

On March 22, the 1B RHR pump discharge check valve (1E11-F031B) failed to close after the pump was secured. After action was taken to manually actuate the valve (operator manipulated disc actuator), the 1D pump was run. Reverse rotation of the 1B RHR pump was observed. When the RHR pumps were secured, the discharge line low water level alarm actuated. The appropriate LCO was entered and corrective maintenance was performed on the valve. The inspectors noted that on at least one previous occasion the RHR discharge check valves had failed to reseat, were seated manually, and the appropriate LCO was not entered. If a LPCI actuation occurs and one pump fails, the failure of the check valve to reseat could render the other pump inoperable. The inspectors concluded that the LCO should be entered until the problem with the check valve is corrected.

On March 15, it was determined that either valve 1E21-F039B or valve 1E21-F040B (CS jockey pump discharge check valve) was not opening fully. The jockey pump was not maintaining the discharge line full of water as required by TS. The system lineup was altered so that a cross connect valve (2E21-F041) upstream of the check valves was opened. This configuration resulted in the CS discharge headers being cross connected (upstream of the check valves). The 'B' loop was filled/vented and the LCO was exited. While in this configuration, certain failures in one loop could have resulted in the partial draining of both loop's discharge headers. Procedure 34SO-E21-001-1S: Core Spray System, provides guidance on filling and venting of the CS discharge headers and operation of the jockey pumps. No guidance is provided specifically directing cross connection of the systems as discussed above. Section 7.4.2 of the procedure addresses an alternate fill and vent path from the condensate transfer system. A caution note states that this portion of the procedure is to be utilized only if both jockey pumps are out of service or inoperable. In response to questioning of this cross connected alignment by a shift supervisor, on March 18, management directed that the condensate transfer fill/vent be utilized to restored CS loop diversity. The TS allowable inoperability period for one CS loop was not exceeded. Subsequently it was discovered that the condensate pressure control valve pressure setting was too low to keep the discharge header full. It was adjusted and this alignment was used to keep the B CS loop full until repairs were completed. While the condensate transfer system is a nonsafety system, loss of fill capability from that source would render one CS loop inoperable.

In March 1992, IST testing of the Unit 1 HPCI system was completed in accordance with 34SV-E41-002-1S: HPCI Pump Operability. During the test, the main oil pump pressure was recorded as 14 psig. The acceptable range on this parameter by the procedure is 17-23 psig. It was not recognized until a later review of the completed procedure that the recorded value of oil pressure was in the required action range. Subsequently, it was noted that a calculation existed which supported HPCI operability for oil pressure as low as 8 psig. The system should have been declared inoperable when the unacceptable data was obtained and the appropriate LCO entered. (If information is readily available to support the operability, then a LCO would not have to be entered). The inspectors had noted a similar instance in Inspection Report 321,366/92-02. In that case the seismic operability of a PSW pump was not properly questioned by plant personnel. The first two above examples involve judgements made by shift personnel and will be addressed by NSAC providing additional guidance to operations personnel. The last example involved an inadequate performance of a surveillance test.

While the above examples involve specific examples of personnel errors or errors in judgement regarding equipment operability, there continues to be examples of TS action statements not being entered during surveillance testing which renders equipment inoperable. The examples usually involve short periods of time during testing when required action for the testing renders the equipment unable to perform its safety functions. While the operators fully realize the equipment is not operable, it is not declared inoperable and the TS action statement is not entered. The inspectors reviewed a NRR response to a TS amendment request involving the EDGs. The response denied the licensee's request to not enter the TS action statement for an inoperable EDG during testing (specifically, during the short periods when the EDG is placed in local control or is inoperable for barring over). The licensee's practice has been to not declare the EDG inoperable during these time intervals. The licensee had concluded from discussions with NRC personnel in previous years that this was acceptable. The inspectors informed site NSAC personnel of the correspondence. Guidance was issued to the operators directing entry into the TS action statement as required.

On April 14, during routine CR observations, one of the inspectors identified an instance in which the Unit 1 HPCI system had been rendered inoperable and the TS action statement was not entered. During adjustment of packing on the 1E41-F001 valve (HPCI Steam supply valve), CR operators were required to stroke the valve. Management had directed that this be accomplished by utilizing portions of 34SV-E41-001-1S: HPCI Valve Operability. This procedure shuts the 1E41-F003 valve (HPCI outboard steam isolation valve) which is upstream of the 1E41-F001 valve. As in the above example of EDG testing, the licensee had not entered a TS LCO for this evolution in the past. The inspector observed an operator place the HPCI auxiliary oil pump in pull-to-lock while cycling the F001 valve.

While this action would ensure that the HPCI stop and control valves would not open during the cycling, it was not the directed method of operation and it clearly rendered HPCI inoperable.

The inspectors have previously discussed entry into appropriate TS LCO for equipment inoperability during testing. IFI 321,366/90-26-02: Failure to Enter Appropriate TS LCO's During Instrumentation Surveillance Testing, addresses a very similar issue. In most of the cases observed by the inspectors, the actions required would usually only be administrative. A TS LCO would be entered and exited without the necessity to complete compensatory actions. The inspectors position, supported by recently issued guidance in NRC Inspection Manual Chapter 9900, has been that the equipment must be declared inoperable and the appropriate TS LCO action statement be entered. The licensee has been moving toward more rigorous tracking of out service equipment and entry into LCOs. However, these changes involve a major shift in the way CR personnel accomplish their duties. The changes will require detailed training and perhaps revisions in administrative procedures involving LCO actions. Further discussion on this issue is expected at a May 6, 1992 meeting with NRR personnel. The inspectors will continue to follow the licensee's actions. IFI 321,366/90-26-02 will continue to be utilized to track the licensee's actions.

No violations or deviations were identified. The inspectors review of the Unit 1 scram concluded that personnel error initiated the transient. No regulatory enforcement actions are appropriate or necessary. The problems noted regarding entry into TS LCO action statements during equipment inoperability periods primarily concern administrative "tracking" of inoperable components. The licensee has recently made improvements regarding instrumentation testing and it is expected that further changes in this area are forthcoming.

3. Surveillance Testing (61726)

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

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

1. 34SV-R43-010-0S: Diesel Generator Fuel Oil Transfer Pump Surveillance Test

2. 57SV-C11-001-2S: Scram Discharge Volume Level Switches Functional Test

3. 34SV-E41-001-1S: HPCI Operability Test

During observation of the SDV level switch functional testing, the inspector noted that the "scribemarks" marking the set points were not readily discernible. Measurements taken by the I&C technicians indicated that the yellow paint marks used as the setpoints during the test were at the correct elevations. The problem of poor markings on displacement type level switches is discussed in Inspection Report 50-321,366/92-05. The licensee has been responsive to the issue and corrective actions are in progress. The inspector observed good radiation work practices and use of appropriate ALARA techniques during the surveillance testing.

No violations or deviations were 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, and exposure control, proper return of equipment to service, and that limiting conditions for operation were met.

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

1. MWO 02-92-1703: Installation of Temporary Batteries and Functional Testing (DCR 88-186)

2. MWO 01-92-1903: Repair of a Packing Leak on Valve (1E41-F001)

3. MWO 02-92-2207: Repair/Replacement of Relay 2C71 ..A

As part of their review of the work associated with the replacement of the 2A EDG battery (DCR 88-186), the inspectors reviewed the safety evaluation and some of the related documentation. The work involved extensive maintenance activities on a major plant component required for accident mitigation and was performed at power instead of during an outage. The new battery has a larger capacity and a lower hydrogen evolution rate than the previous battery. Available information indicates that the performance of the installed battery had been decreasing. The installation of the new battery will improve the capacity margin. The inspectors did not identify any discrepancies associated with the use of a temporarily installed battery during the replacement or the installation work itself. It was noted that the safety evaluation included analysis which supported the modification being performed at power. Additionally shutdown risk management issues were considered during the decision to perform the work at power.

b. EDG Inoperability Due to Inadequate Component Identification During Maintenance (62703) (Unit 2)

On ' c.1 16, 1992, maintenance personnel erroneously removed the Em. ncy Power Diesel Generator 2C2 (2Y52-C101C) fuel oil transfer pump from service. The resulting condition rendered the 2C EDG inoperable for approximately 19 hours. MWO 2-91-1058 addressed rebuilding the 2C1 2Y52-C001C fuel oil transfer pump/motor due to high vibration measurements obtained during testing. Equipment clearance 2-92-232 was used to support the MWO. Electrical maintenance personnel verified the clearance as required. Two electricians then proceeded to the location of the motor in order to remove the power cabling in preparation for mechanical maintenance personnel to remove the motor and pump. They de-terminated the 2C2 fuel oil transfer pump motor instead of the 2C1 fuel oil transfer pump motor. Mechanical maintenance personnel then removed the incorrect equipment. 2Y52-C101C was rebuilt in the maintenance shop. Approximately, 19 hours later the error was discovered when maintenance personnel were preparing to reinstall the pump/motor.

Since the 2C1 motor had been tagged out for service by clearance 2-92-232, and then the 2C2 motor was removed, the 2C EDG, (2R43-S001C) did not have a fuel transfer pump available. In accordance with TS 3.8.1.1b, this rendered the EDG inoperable. TS 3.8.1.1b permits one Unit 2 EDG to be inoperable for up to 72 hours, providing other required equipment is operable. The inspector's review indicated that the other required equipment was operable during the period. However, for 19 hours operations personnel were not aware of the inoperable EDG, therefore, they failed to comply with TS requirement of demonstrating the operability of the remaining A.C. sources by performing TS requirement 4.8.1.1.1a (within 1 hour and at least once per 8 hours thereafter).

The inspectors discussed the incident with maintenance management, reviewed the associated documentation, and inspected the area where the pumps are located. Additionally, the inspectors reviewed maintenance training material which is intended to deter such occurrences. The following items and concerns were noted:

-The motors are located in a below grade, six feet in diameter enclosed space. The space is accessed by a ladder and is fairly confined. The MPL numbers for the pumps were not marked on the equipment, but were located on white label on the wall behind each pump.

-The MPL numbers for the two pumps, 2Y52-C101C and 2Y52-C001C are very similar and it could be difficult to distinguish between the two numbers.

-In addition to rendering the 2C EDG inoperable, the inattention to detail created a potential serious safety hazard. The electricians verified that no voltage was present on the cables prior to de-termination. The circuit indicated no voltage present since the day tank was above the level at which the fuel oil transfer pump would be energized to replenish the day tank from the storage tank. If the level circuity had been activated on the pump while personnel were removing the power cables, a serious electrical shock could have occurred.

-Several maintenance department training lectures stress the importance of correctly identifying components before commencing maintenance activities. It is also emphasized during ongoing and refresher training. Hatch does not include specific procedural steps or documentation addressing component identification. It is considered a basic activity and is expected to be performed by all maintenance personnel. Personnel are to compare the MPL number on the component with the number referenced in the MWO or procedures. Although no significant problems involving component verification for maintenance activities have been noted in the recent past, the inspectors have not noted particularly rigorous application of component identification/verification process.

-The licensee's SOR on this event and a root cause determination performed by the maintenance department both noted the labeling and MPL similarity as previously discussed.

-The licensee's corrective actions included counseling the individuals involved regarding their inappropriate actions and disqualifying them from their normal duties until they were retrained. Additionally, MPL tags were placed directly on the motor and pump. This event will be included in the mechanical maintenance continual training session.

The inspectors concluded that this event was caused by personnel error and failure to follow procedure on the part of the maintenance personnel involved. The error involved an activity (component identification) that is a critical element in conducting safe maintenance activities. Several instances of failure to follow procedure and/or inattention to detail in other onsite groups have been noted in recent months. Those problems did not have the safety significance of this item. This event is considered a significant deficiency since it rendered an emergency power diesel generator inoperable. This issue is identified as Violation 50-366/92-08-02: Inadequate Component Identification During Maintenance Activities.

One violation was identified.

5. Motor Operated Valves Thermal Overloads Not Bypassed (71707) (90700)

As part of the licensee's response to GL 89-10, Safety-Related Motor-Operated Valve Testing and Surveillance, thermal overloads in the control circuits to MOVs were reviewed. The licensee identified a total of 96 safety related valves which apparently have operative thermal overloads (the overload function was not permanently bypassed or jumpered). While the plant drawings of these valves indicated that jumpers were not installed, some vendor drawings indicated that jumpers were installed. The licensee is completing walkdowns to verify the actual configurations. The absence of jumpers does not necessarily mean that the valves will not function properly. If the thermal overloads are sized properly (with consideration given to all adverse operational conditions), such that they will not trip prematurely, the valve will be able to accomplish its intended safety function.

Of the 96 safety related valves suspected to be without bypasses, 39 of the valves are considered EQ. The remote starters for these valves are located on the 130 foot level of the RB. One of the inspectors attended a March 18, meeting on this issue involving the licensee, A/E representatives and SNC personnel. The 39 EQ MOVs without bypasses were addressed. During an EQ lab test conducted in 1989, the overloads were jumpered to complete the testing. The test conditions included a temperature of 219 degrees F and load current flowing through the overloads for 12 minutes (prior to tripping of the overloads occurring). The 130 foot elevation of the RB is postulated to get very close to 219 degree F (216 degrees F) in certain DB scenarios.

The inspector was provided a list of the subject valves. The inspector referred to both the current guidance on licensee actions that should be taken when equipment is discovered to be potentially nonconforming and GL 88-07, Modified Enforcement Policy Relating to 10 CFR 50.49 "Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants. In this case, GL 88-07 requires the licensee to; make a prompt determination of operability, take immediate steps to establish a plan with a reasonable schedule to correct the deficiency, and have a written JCO.

The licensee stated that ba.·d on the available information, the valves were considered operable. The licensee then developed a JCO which addressed each of the valves in detail. The JCO was provided to the inspectors on March 24. It consisted of a description of the problem, a general discussion of factors supporting operability of the valves, and a section addressing each of the valves in question. The inspectors concluded that sufficient analysis and data was provided for reasonable assurance that the equipment would perform its safety function if called upon. The JCO was of higher quality than a similar JCO involving non-Q breakers reviewed by the inspectors and discussed in Inspection Report 50-321,366/91-18. The JCO was primarily based on the actual EQ test conditions which involved energization of the control circuitry for 12 minutes and a required valve stroke time of typically 30 seconds support operability of the valves. The licensee stated that current plans were to inspect the MCCs to verify the current overload configuration and then during the next scheduled refueling outage install the bypasses.

Subsequently the licensee determined by walkdown that only 27 (13 on Unit 1, 14 on Unit 2) of the 39 suspected valves had thermal overloads which were not jumpered. During the outage on Unit 1 (see paragraph 2b of this report) jumpers were installed on the 13 valves on Unit 1. The 14 valves on Unit 2 remain unjumpered. The licensee plans to install bypasses on these valves at the next available outage.

On April 13, 1992, the inspectors were provided a safety assessment addressing the 57 non-EQ, safety-related MOVs which potentially have operative (unjumpered) thermal overload trip functions. The assessment concluded the operability of the valves was not in question. The primary reasoning was that the expected failure mode for a spurious thermal overload trip involves high ambient temperatures (which is not expected for these valves). The inspectors noted that in January 1990, a failure of a heater strip of a thermal overload relay occurred. This resulted in the inability to open the HPCI injection valve, 2E41-F006, during a reactor scram recovery (LER 366/90-001). Installation of jumpers would not have enabled the valve to function after that failure. The jumpers bypass only the trip relay; the overload devices remain in the power circuit to the valve motor.

The assessment also stated that the 57 MOVs will be reviewed to verify the actual installed configuration. If it is concluded that a jumper is required (see discussion of "essential" below), the jumper will be installed and the applicable drawings corrected. After discussions with the licensee, the inspectors concluded that available information at this time indicates the valves are fully operable.

In addition to the primary issue of inadequate control of important plant equipment design configuration, the inspectors questioned if the licensee had failed to meet its commitments involving the MOV thermal overloads. The inspectors did not identify any documented commitments to RG 1.106, Thermal Overload Protection for Electric Motor-Operated Valves Rev. 1. Section 8.3.1.1.2 of the Unit 2 FSAR states that the overloads of "essential" starters are permanently bypassed. The licensee interprets "essential" to include ECCS or PCIS valves. The inspectors discussed this issue with NRR and regional personnel knowledgeable on the subject and no further guidance on the definition of essential was identified.

The inspectors concluded that the major concern on this issue is the licensee's inadequate design control processes. Numerous drawings of safety related equipment circuitry were incorrect. Several valves starters on which the thermal overloads should have been jumpered were not. The licensee was not aware of which valves had permanent jumpers installed and which ones did not. A similar weakness involving design control was recently identified by the inspectors. URI 321,366/92-05-01: Incorrect Level Setpoints in the Setpoint Index Document, addressed incorrect level switches/instrument setpoints. The inspectors brief review had indicated several of the elevation setpoint values listed in the index were incorrect. The licensee and the A/E are conducting a detailed review of this issue. Included in this review is identification of the cause of the errors. The inspectors noted that a similar earlier issue had resulted in a violation. (Violation 50-366/91-04-01; Failure to Implement a Design Modification Resulting in Incorrect HPCI CST Level Switch Setpoints).

The setpoint index and the MOV jumper issue are considered significant weaknesses in the design control process. Accurate incorporation of design basis and regulatory requirements into implementing drawings and procedures is required by Criterion III of 10 CFR 50, Appendix B. This item is identified as Violation 321,366/92-08-01: Inadequate Design Control Resulting in Incorrect Design Documentation and Configuration. URI 321,366/92-05-01 is closed.

One violation was identified.

6. Information Meeting With Local Officials (94600)

On March 17, 1992 the inspectors held an information meeting with the Appling County Board of Commissions. The Chief of Region II Reactor Projects Section 3B and the Region II Public Affairs Officer were also in attendance. Approximately 20 members of the public were present in addition to the Board. The Board was provided an overview of the organization of the NRC, a summary of plant status, and a discussion of the inspection program. The telephone numbers of NRC contacts were provided. No questions were asked either during or following the presentation. A meeting was held on March 3, 1992 with the Toombs County Board (Inspection Report 50-321,366/92-05) and one of the inspectors has met with several EMA officials previously.

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

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

a. (Closed) LER 366/90-11: Inadequate Procedures and Personnel Error Result in Missed TS Surveillance. This LER addressed a failure to perform compensatory testing during FPM inoperability. Violation 50-366/90-23-01: Failure to Perform TS Required Compensatory Measures During FPM Inoperability also addressed this issue. Inspection Report 321,366/91-18 contains a detailed discussion of the inspectors review of the licensee's corrective actions. The violation was closed out at that time. Based on that review and no further noted problems in this area, LER 366/90-11 is closed.

b. (Closed) LER 321/90-022: Group 5 Primary Containment Isolation on RWCU High Differential Flow. This LER addressed a group five isolation which occurred during restoration of the RWCU system to service following maintenance. Procedure 34SO-G31-003-1S: RWCU System, did not contain adequate guidance to prevent rapid system filling which occurred as a result of opening the RWCU pump suction isolation valve. A similar incident had occurred in early 1989 (LER 50-321/89-001). Corrective actions for that event included revisions of some parts of 34SO-G31-003-1S but not the portion in use during this event. Procedures 34SO-G31-003-1S and 2S were subsequently revised. Additionally, a request to revise the TS to allow the RWCU isolation signal to be bypassed for up to 2 hours during system restoration or testing was submitted to the NRC in September 1990. The inspectors also noted that during the investigation into a recent RWCU isolation (LER 321/91-27), improper installation of instrument sensing lines for a differential pressure transmitter caused the event. When portions of the RWCU system are drained, the instrument tubing partially drains and a false high RWCU differential flow signal results. Apparently, the tubing does not slope downward the entire route from process piping to the instrument. During the next outage, the Unit 2 sensing lines will be examined. Rerouting of the Unit 1 lines is being evaluated. It is possible that this configuration has contributed to previous RWCU isolations. Based on this review, LER 321/90-22 is closed.

c. (Closed) LER 366/90-002 (Revision 1) and LER 366/90-006. These LERs addressed two similar instances of partial RWCU isolations. The first example (LER 366/90-002) occurred in January 1990. During opening of the HPCI discharge valve (2E41-F006) during hot shutdown conditions, the RWCU outboard isolation valve (2G31-F004) shut. Since the RWCU return line connects to the HPCI discharge line, opening of the 2E41-F006 valve caused a momentary increase in RWCU return flow. In August 1990 a second example occurred during operation of a RWCU demineralizer isolation valve (2G31-F053B). In both cases only the outboard isolation valve (2G31-F004) shut and it appeared to shut almost immediately upon receipt of the RWCU LDS alarm (high RWCU differential flow) in the CR. Expected system response is actuation of both the inboard and outboard isolation valves (2G31-F001 and F004) after a 45 second time delay. Several similar events had occurred in 1989. Testing of the time delay relay (2G31-R616D) for the 2G31-F004 valve channel (following the January 1990 event) indicated that intermittent contact bounce had caused the actuations. The bounce was of sufficient duration to actuate downstream contacts and seal in an actuation signal. Replacement of the relay was delayed to an outage since it involved work in a scram sensitive panel. DCR 2H90-026 was completed in April 1991. It replaced the GE CR2820 model relays with Agastat relays and more rigidly mounted the relays. Based on this review and the completed corrective actions, these items are closed

8. Exit Interview

The inspection scope and findings were summarized on April 20, 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
50-321,366/92-08-01	Open	Violation - Inadequate Design Control Resulting in Incorrect Documentation and Configuration (paragraph 5)
50-366/92-08-02	Open	Violation - Inadequate Component Identification During Maintenance Activities. (paragraph 4b)

9. Acronyms and Abbreviations

AC - Alternating Current
A/E - Architect Engineer
ALARA- As Low As Reasonably Achievable
APRM - Average Power Range Monitor
BWROG- Boiling Water Reactors Owners Group
CFR - Code of Federal Regulations
CR - Control Room
CRD - Control Rod Drive
CS - Core Spray
CST - Condensate Storage Tank

DB - Design Bases
DC - Deficiency Card
DCR - Design Change Request
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EHC - Electro Hydraulic Control System
EMA - Emergency Management Agency
EOC - Emergency Operations Center
EP - Emergency Preparedness
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
GL - Generic Letter
GPM - Gallons per Minute
HELB - High Energy Line Break
HPCI - High Pressure Coolant Injection System
I&C - Instrumentation and Controls
IFI - Inspector Followup Item
IRM - Intermediate Range Monitor
IST - Inservice Testing
JCO - Justification for Continued Operation
LCO - Limiting Condition for Operation
LDS - Leakage Detection System
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
LPCI - Low Pressure Core Injection
MCC - Motor Control Center
MCRECS- Main Control Room Environmental Control System
MFP - Main Feed Pump
MOV - Motor Operated Valve
MPL - Master Parts List
MWO - Maintenance Work Order
NCV - Non-cited Violation
NPRDS- Nuclear Plant Reliability Data System
NRC - Nuclear Regulatory Commission
NRR - Office of Nuclear Reactor Regulation
NSAC - Nuclear Safety and Compliance
PCB - Power Circuit Breaker
PCIS - Primary Containment Isolation System
PM - Preventive Maintenance
PSIG - Pounds Per Square Inch Gauge
PSW - Plant Service Water System
RB - Reactor Building
RCIC - Reactor Core Isolation Cooling System

RFP - Reactor Feedwater Pump
RG - Regulatory Guide
RHR - Residual Heat Removal System
RPS - Reactor Protection System
RPT - Recirculation Pump Trip
RTP - Rated Thermal Power
RWCU - Reactor Water Cleanup System
RWL Reactor Water Level
Rx - Reactor
SAER - Safety Audit and Engineering Review
SDV - Scram Discharge Volume
SNC - Southern Nuclear Operating Company
SOR - Significant Occurrence Report
SOS - Superintendent of Shift (Operations)
SP - Suppression Pool
SPDS - Safety Parameter Display System
SRM - Source Range Monitor
SRO - Senior Reactor Operator
SRV - Safety Relief Valve
STA - Shift Technical Advisor
TBV - Turbine Bypass Valve
TS - Technical Specifications
TSC - Technical Support Center
URI - Unresolved Item