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

Report Nos.: 50-321/95-18 and 50-366/95-18

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: August 6 - September 2, 1995

Inspectors: D. A. Seymour 9.28.95
for Bob L. Holbrook, Sr. Resident Inspector Date Signed
D. A. Seymour 9.28.95
for Edward F. Christnot, Resident Inspector Date Signed

Accompanying Inspector: James A. Canady

Approved by: B. R. Bonser for 9/29/95
Pierce H. Skinner, Chief, Date Signed
Project Section 3B
Division of Reactor Projects

SUMMARY

Scope: This routine resident inspection involved inspection in the following areas: plant operations, maintenance, engineering, and plant support activities. The inspectors conducted backshift inspections on the following dates: August 6, 9, 12-14, 16, 20, 27, 29-30, and September 2, 1995.

Results: One violation with two examples of failure to follow procedure, and one inspector followup item were identified

Operations:

One inspector followup item was identified concerning the Unit 2 rapid decrease in condenser vacuum and subsequent manual scram (paragraph 2.b).

One of the two examples of the violation for failure to follow procedure involved hydrogen water chemistry flow changes. A procedure was not followed while adjusting hydrogen injection

ENCLOSURE 2

flow on Unit 1. This resulted in unnecessary exposure to personnel during entry into the condenser bay (paragraph 2.d).

The inspectors reviewed the results of the Institute of Nuclear Power Operations evaluation report issued in September 1995. The report did not substantially deviate from the most recent Nuclear Regulatory Commission (NRC) perspective of plant performance. The review did not identify any significant issues that would require NRC Region II follow-up action (paragraph 2.e).

A strength in attention to detail was identified for the plant equipment operator who identified a problem with the control building elevator. A ground in the elevator direct current control circuit was found to be the cause of a problem associated with the 1D 600 volt bus that placed the unit in a 12 hour to hot shutdown limiting condition for operation (paragraph 2.f).

Maintenance:

Work activities were performed safely and in accordance with procedures for the removal of a piece of wood found in the suction section of the 2B plant service water pump. Appropriate actions were taken for determining the root cause of the low pump discharge pressure. Coordination between the involved departments was very good (paragraph 3.e).

Operations personnel detection and response to a main turbine control valve problem was timely. The problem was due to the blockage of the associated electro-hydraulic control servo filter. Coordination between involved personnel was effective and the filter replacement activities were satisfactory (paragraph 3.f).

The second example of the violation for failure to follow procedure involved intake structure inspection activiites. Divers entered the intake structure pump pit area to perform inspection activities without the use of a procedure. A service water pump was declared inoperable when a section of the diver's life, air, and communication line entered into the suction of a service water pump. A weakness was identified in the lack of clear communications between maintenance and maintenance support. The lack of clear communications contributed to the failure to follow procedure (paragraph 3.g).

Engineering:

A strength was noted for a system engineer's attention to detail with respect to the identification of a problem with the Unit 1 and 2 diesel generator voltage regulator logic circuit (paragraph 4.a).

The most recent operability test of the 1B diesel generator did not reveal high crankcase pressure. The inspectors concluded that the recurring high crankcase pressure transient problem was corrected following replacement of the lube oil cooler (paragraph 4.b).

A strength was identified with engineering and chemistry personnel who took prompt actions responding to a suspected fuel leak on Unit 1 (paragraph 4.c).

An additional example of balance of plant systems resulting in plant transients was identified. Two recirculation pump runbacks, due to the fast opening of the feedwater pump minimum flow valves, occurred on Unit 1. Management's attention to BOP systems that cause plant transients could have been more thorough (paragraph 4.d).

Plant Support:

A strength was identified in the licensee's ability to respond to security events with respect to overt threats. (paragraph 5.a).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

J. Anderson, Unit Superintendent
D. Crowe, Hatch Licensing Manager, Southern Nuclear
D. Bennett, Chemistry Superintendent
*J. Betsill, Unit 2 Operations Superintendent
*C. Coggin, Training and Emergency Preparedness Manager
*D. Davis, Plant Administration Manager
P. Fornel, Maintenance Manager
*O. Fraser, SAER Supervisor
E. Gibson, Reactor Engineering Supervisor
*R. Godby, Maintenance Superintendent
G. Goode, Engineering Support Manager
J. Hammonds, Regulatory Compliance Supervisor
*R. King, Acting Engineering Support Manager
*W. Kirkley, Health Physics and Chemistry Manager
R. McGinn, Security Operations Supervisor
*T. Metzler, Acting Manager Nuclear Safety and Compliance
C. Moore, Assistant General Manager - Operations
*J. Payne, Senior Engineer
*D. Read, Assistant General Manager - Plant Support
*P. Roberts, Outages and Planning Manager
*K. Robuck, Manager, Modifications and Maintenance Support
H. Sumner, General Manager - Nuclear Plant
*J. Thompson, Nuclear Security Manager
S. Tipps, Nuclear Safety and Compliance Manager
P. Wells, Operations Manager

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

NRC Resident Inspectors

B. Holbrook
*E. Christnot

Accompanying Inspector

*J. Canady

Supporting Inspector

D. Seymour, Project Engineer

NRC management/officials on sight during inspection period:

K. Jabbour, Senior Project Manager, Project Director II-2, NRR, Plant Hatch
L. Reyes, Deputy Regional Administrator, Region II
W. Russell, Director, Nuclear Reactor Regulation

* Attended exit interview

On August 16, NRC management visited plant Hatch. The NRC toured the plant, held discussions with GPC corporate and plant management, and interviewed department managers. Discussions included plant performance, current and future regulatory issues, and other generic topics. The NRC concluded the open exchange of information was very productive.

On August 23, the NRC participated in a full participation graded EP exercise. The Region II Regional Administrator was the Site Team Leader. The site team reported to the site to monitor and evaluate licensee activities. The Site Team Leader assumed the position of Director of Site Operations to assess total response capabilities and oversee NRC activities.

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

2. Plant Operations (71707) (71750) (92901) (93702)

   a. Operations Status and Observations

      Unit 1 began the report period at 100% RTP. On August 14, power was decreased to 55% RTP for flux tilt testing due to failed fuel. Power was returned to 100% RTP on August 22. Power was decreased to 90% RTP and returned to 100% RTP from August 23 to 24 due to high temperatures in the main generator. Power was decreased to approximately 80% RTP on August 29, due to a suspected blocked EHC strainer to the number 2 turbine control valve. Power was returned to 100% on the same day. The unit operated at that power level with the exception of scheduled power reductions for routine testing.

      Unit 2 began the report period at 97% RTP. The unit operated in a pre-refueling coast down mode until September 1. Power was decreased from 90% to 60% due to a cooling tower fill material failure. The unit was manually scrammed on September 2, due to rapidly decreasing condenser vacuum. Unit 2 was in hot shutdown at the end of the report period.

      Activities within the CR were routinely monitored. Observations included CR 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 were monitored. ECCS system lineups, containment and secondary containment integrity, reactor mode switch position, scram discharge volume valve positions, and rod movement controls were monitored.

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

Reactor Building	Diesel Generator Building
Fire Pump Building	Intake Structure
Station Yard Zone	Turbine Building
Refuel Floor	Radwaste Building

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 by TS. Observed operating parameters were verified to be within TS limits.

b. Unit 2 Manual Scram

The inspectors were informed that on September 1, the fill material in cell 20 of cooling tower 5 had collapsed and blocked the discharge of the tower to the main flume. Reactor power was reduced to 60% RTP and one condenser circulating pump was secured. The cooling tower was isolated and reactor power was stabilized at 66% RTP. The plant operators eventually initiated a manual scram due to a continued loss of condenser vacuum.

One inspector responded to the site and observed the licensee's activities. The inspector verified the plant was in a stable condition with normal level control. No ECCS system was required to initiate. The inspector discussed the manual scram, plant status and the initiating event with various CR and supervisory personnel.

Discussions and additional followup by the inspectors revealed that the vacuum in the 2A condenser began a gradual decrease from 25.5" Hg. The operators periodically lowered reactor power in an attempt to maintain condenser vacuum above the administrative limit of 25" Hg. Power was eventually reduced to about 30% RTP. The operators noted during the power reductions that the 2A condenser appeared to be losing vacuum quicker than the 2B. With vacuum below 23" Hg, condensate temperature at 153°F, a low vacuum alarm (BELLOWS FAILURE) present, and the vacuum continuing to decrease, the operators initiated a manual scram. The inspectors will continue to review the licensee's evaluation of actions with respect to the manual scram. This event is identified as, IFI 50-366/95-18-01, Additional Reviews of Unit 2 Manual Scram Due to Rapidly Decreasing Condenser Vacuum.

c. ESF Walkdown of Selected Primary Containment Isolation Components

The inspectors conducted an ESF walkdown of a representative sample of accessible portions of PCIS components on Units 1 and 2 to verify operability. The representative sample consisted of valves, CR indications, and breakers associated with selected isolations found in the six isolation groups of TSs. The inspectors independently verified, in the CRs for both units, that selected valves, switches, and electrical board lineups were in accordance with procedures 34SV-T23-002-1/2S: PCIV Position Indication Status Check, Revision 0. The inspectors, with the assistance of operations personnel, viewed the internals of the relay logic cabinets for the MSIV isolation. The general condition of the cabinets' internals was good and the inspectors did not identify any signs of insulation fraying from wires, debris, loose material or jumpers.

Selected accessible valves were examined. A walkdown of these spaces verified satisfactory housekeeping and cleanliness. The inspectors verified that these valves were in the required position and did not exhibit indications of gross packing leakage, bent or galled stems, missing handwheels, or improper labeling. The breakers for the valves were verified to be in their required position.

In preparation for the inspection a review of the applicable sections of the FSAR, P&IDs, and TS were conducted. During this review the inspectors noted that RWCU Differential Flow High isolation signal was not a requirement in the new TS. Further research conducted by the inspectors revealed that this signal was deleted based upon a GE analysis that concluded other protective isolation instrumentation were sufficient for the mitigation of the design basis events.

The inspectors did not identify any safety significant issues that would affect system operability. The inspectors concluded the PCIS valves, switches and electrical board lineup were in accordance with procedures, P&IDs, and the new TSs. No generic maintenance problems were identified.

d. Failure to Follow Procedure Results in Unnecessary Exposure.

On August 28, the inspectors were informed that a maintenance team received unnecessary exposure during a Unit 1 condenser bay entry performed to isolate an EHC leak on August 27. HP personnel conducted an investigation into the problem to identify deficiencies and to recommend corrective actions.

The inspectors discussed the problem with licensee management, personnel conducting the investigation, and operations personnel. Additionally, a review of operator procedures, logs, HP surveys and other documentation was conducted.

On August 26, a PEO discovered the main turbine EHC tank level had decreased from the previous shift's readings. A maintenance team was formed to conduct a high radiation entry (greater than 500 mrem/hr) into the condenser bay to identify and isolate the leak.

The maintenance team consisted of a HP technician, a mechanic, and an operator.

In preparation to make the high radiation area entry, a PEO was dispatched to lower hydrogen injection flow to 8 SCFM. He reported to the CR that hydrogen flow was at 8 SCFM and that he had placed the hydrogen controller back in the "external" mode.

Following the ALARA briefing, the maintenance team entered the condenser bay. During the entry the HP technician observed that radiation levels were between 4 and 8 rem/hr, in excess of what would be expected for reduced hydrogen injection. The team determined what would be required to isolate the leak and exited the area.

The team contacted the HP foreman and operations SOS to discuss the higher than expected radiation levels, and inquired about the urgency of the job for isolating the leak. Operations personnel communicated to the team that the job was urgent. Also, the team was informed again that the hydrogen flow rate had been decreased to about 8 SCFM. The team reentered the condenser bay and attempted to isolate the leak.

Later, operators in the CR conducting a normal board walkdown to monitor plant parameters observed that the hydrogen recombiner temperatures and MSL radiation monitors indicated higher than expected for reduced hydrogen flow. A PEO was dispatched to the hydrogen system control panel and identified that the flow rate was at 45 SCFM instead of the expected 8 SCFM. The SOS initiated an investigation into the problem. The investigation revealed that the controller was placed back in the "external" mode following the flow rate reduction. This allowed the flow to automatically increase back to 45 SCFM.

The inspectors were informed by the HP technician conducting the investigation that the total excess dose received by the maintenance team was approximately one man-rem. This was based upon previous known dose rates calculated at various hydrogen injection flow rates. Individual maintenance team members received 392 mrem, 599 mrem, and 715 mrem. The inspectors verified that no team member exceeded exposure guidelines.

The inspectors reviewed training material used to train PEOs on Hydrogen Injection System operation and configuration. The inspectors concluded that lesson plan, PE-LP-07301-01: Hydrogen Injection System, dated July 19, 1995, contained appropriate information on system operation and configuration.

The inspectors reviewed procedure 34SO-P73-001-1S: Hydrogen Water Chemistry Hydrogen Injection, Revision 11, Section 7.3.4, Manual Operation of Hydrogen Controller. The inspectors confirmed that the information contained in the procedure matched the indications and controls located on the local hydrogen control panel. The inspectors concluded that the procedure provided adequate information to establish a desired hydrogen flow rate. Procedure step 7.3.4.2 required, in part, to confirm or place Hydrogen Controller 1P73-R025, to the "Internal" mode of control. Additional procedure steps provided instructions to adjust a potentiometer to obtain the desired flow rate. The inspectors noted that the procedure never directed the controller be placed back to the "External" or load following mode of operation.

This failure to follow procedure while adjusting hydrogen injection flow is an example of VIO 50-321,366/95-18-02: Failure to Follow Procedures While Performing Hydrogen Water Chemistry Flow Changes and Intake Structure Inspection Activities.

The inspectors later confirmed that the EHC leak was repaired. The inspectors concluded that HP coverage for the job was satisfactory. The HP technician demonstrated an awareness of the greater than expected radiation levels and a questioning attitude.

The inspectors also concluded that additional steps could have been performed by HP and/or operations to verify the hydrogen injection flow rate; the perceived urgency of the job may have contributed to the problem; and the information provided by the PEO that the controller was placed in the "External" mode of operation was not acted upon by operations personnel.

The inspectors further concluded that personnel errors continue to occur. A previous violation with multiple examples associated with inattention to detail and a failure to follow procedures is documented in IR 50-321,366/95-08.

e. INPO Evaluation Report Review

The inspectors reviewed the results of the INPO evaluation report issued in September 1995. The INPO evaluation was conducted from May 15 - 22, 1995. The evaluation focussed on plant safety, management systems and controls, and identification of areas needing improvement. The report did not substantially deviate from the NRC perspective of plant performance. The review did not identify any safety significant issues that would require NRC Region II follow-up action.

f. Undervoltage and Load Shed of 1D 600 VAC Bus

On August 29, the inspectors were informed that Unit 1 was about to enter a 12 hour to HSD RAS. Operators in the CR had received alarms that indicated an undervoltage condition on 1D 600 V bus. The non-essential loads were shed from the bus. As a result the Division II station service battery chargers were de-energized. The battery chargers normally supply power to 125/250 VDC switchgear 1B (1R22-S017), and maintain the batteries charged. Due to the loss of bus

1R22-S017, TS actions require the battery chargers be restored within 2 hours, or the unit be in HSD within the next 12 hours.

One of the inspectors reported to the site to observe and assess the licensee's troubleshooting activities and to monitor operation's preparation for the unit shutdown. The inspector noted that operations and maintenance management were present and provided supervisory oversight. The inspector discussed the problem with plant management and craftsmen. The inspector noted that the bus problem did not result in any ECCS or ESF actuation. However, approximately 2.5 hours after the bus undervoltage problem, the RPS 1B MG set tripped during troubleshooting activities. This initiated an ESF actuation and partial Group 1 and Group 2 isolation. All systems responded as designed. The RPS was placed on alternate power. The isolations were reset and all systems were placed back in service. The ERT later determined that the 1B RPS supply breaker opened due to EMI caused by the ground.

During the troubleshooting activities a PEO smelled smoke in the control building, and after investigation, observed that the control building elevator was traveling up and down with no passenger. Operations initiated a clearance to de-energize the elevator. During the clearance activities, electrical maintenance and engineering personnel observed indications that linked the bus problem to the elevator problem. The elevator was isolated from the 600 VAC bus and all bus loads were returned to operation. The unit shutdown RAS was terminated. Licensee management initiated an ERT to further evaluate the problem and make recommendations for corrective actions.

The inspectors identified the PEO's actions as a strength in attention to detail. The inspectors concluded that operations, maintenance and engineering personnel were responsive to the ground problem and provided very good supervisory oversight.

One IFI and a violation were identified.

3. Maintenance Activities (61726) (62703) (71750)

a. Maintenance Work Activities

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 fire hazards, cleanliness, exposure control, proper return of equipment to service, and that limiting conditions for operation were met.

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

1. MWO 2-95-2575: Investigate and Repair the Loss of Power to Lundell Cabinet Alarms

2. MWO 2-95-2340: Removal of 2B PSW Pump for Inspection

3. MWO 1-95-1716: Air Test of Heat Exchanger Removed From 1B EDG

The inspectors observed that personnel consistently used procedures and exhibited strong communication practices. The inspectors did not identify any specific concerns.

b. Continued Investigation of EDG 1B High Crankcase Pressure Trip

The inspectors continued to follow the licensee's activities involving the 1B EDG high crankcase pressure. The inspectors reviewed the results of an air test performed on the suspected lube oil cooler (previously removed from the EDG). The test was conducted in accordance with procedure 52PM-R43-015-OS: EDG Turbocharger and Heat Exchanger Inspection, Revision 4. The air test consisted of pressurizing the tube side of the heat exchanger to 100 psig and monitoring the shell side for any increase in pressure. The test lasted for a total of 33 hours. During the test the tube side decreased from 100 psig to 78 psig and the shell side increased from 0 psig to 23 psig.

The inspectors concluded from the review and discussions with the licensee that the heat exchanger had a small leak from the tube side to the shell side. The leak allowed enough water to accumulate in the EDG lube oil cooler to cause a high crankcase pressure trip the EDG.

c. Surveillance Observations

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:

1. 34SV-R43-001-1S: Diesel Generator 1A Monthly Test
2. 34SV-P41-001-2S: Plant Service Water Pump Operability
3. 34SV-E11-001-1S: Residual Heat Removal Pump Operability
4. 42SV-FPX-004-0S: Fire Pump Test
5. 34SV-R43-003-1S: Diesel Generator 1C Monthly Test

The inspectors observed that personnel consistently used procedures, exhibited strong communication practices, and were proficient with the tasks. No deficiencies were identified.

d. 42SV-R42-007-0S: Battery Charger Capacity Tests

The inspectors reviewed the battery charger testing. A resistance load bank was used to determine the electrical amperage output of the Unit 2 EDG, Unit 1 vital AC and the Unit 2 station service battery chargers. A problem with the 125/250 V Station Service Battery Charger 2C (2R42-S028) was identified. The battery charger resistors were subsequently replaced. The battery charger was successfully tested and returned to service.

e. PSW Pump 2B Low Discharge Pressure Problem

The 2B PSW pump was declared inoperable on August 13, due to a low discharge pressure. I&C calibrated the pressure and flow instrumentation. The subsequent pump operability test was unsatisfactory. Following an engineering evaluation, the licensee replaced the pump. The inspectors observed the removal of the existing pump and noted a piece of drift wood in the suction of the pump. The inspectors estimated the dimensions of the wood to be approximately two inches in diameter and approximately ten inches long. The length of time that the piece of wood had been in the suction pit bay before entering the suction of the PSW pump was not known. The licensee decided to place the same pump back in service since there was no evidence of damage to the pump. A refurbished motor was attached to the pump. The inspectors observed the pump operability test. The pump test was satisfactory, but the pump differential pressure was in the Alert range. The pump was in this range prior to the low discharge pressure problem. The corrective action for the Alert range was to double the testing frequency of the pump. The inspectors reviewed procedure 31GO-INS-001-0S: ISI Pump and Valve Operability Tests, Revision 7, and confirmed that doubling the testing frequency was the correct action for a pump with differential pressure in the Alert range.

The inspectors concluded that the licensee took the appropriate actions for determining the root cause of the low PSW pump discharge pressure. It was also concluded that work activities at the intake structure during the removal of the pump was performed safely and in accordance with procedures. The maintenance department coordination with operations, engineering, and security was effective.

f. EHC Filter Problem

On August 29, the inspectors observed that the MWe output on the digital meter located in their office had decreased. The inspectors proceeded to the CR to identify any problems. The inspectors were informed that the number 2 TCV had slowly drifted toward the closed position. Power was reduced to approximately 80% RTP for a condenser bay entry to investigate EHC servo filters for blockage. These actions were taken based upon vendor recommendations. This was a recurring problem. Operations personnel had seen similar TCV responses in the past that were due to blockage of the EHC servo filter. Details of past EHC problems are documented in IR 50-321,366/94-13.

Troubleshooting and inspection performed by maintenance personnel confirmed that the number 2 EHC TCV servo filter was blocked with what appeared to be black sediment. GE evaluated the results of the maintenance findings and recommended replacing the filters in all TCVs. The licensee replaced these filters and the EHC servo filters associated with the CIVs.

EHC fluid samples were sent to two offsite laboratories for independent analyses. The fluid analysis results from both laboratories were normal, well within specifications, and typical of what had been seen in the past.

The sediment from the number 2 TCV servo filter and several of the replaced expended filters was sent to the independent laboratory for analysis. The results indicated that the sediment material was a combination of ordinary dirt and fine rayon fibers. The dirt was analyzed to determine if it had any resemblance to or attributes of Fuller's earth, which would indicate a break down of these filters. No resemblance or similar attributes were identified. It was concluded that the dirt was within the specifications of what would normally be expected to be found in the system. The analysis of the materials from which the filters were manufactured did not reveal any rayon substances.

At the end of this report period, the licensee did not know the source of the rayon substance. The licensee noted from industry experience that rayon has been found in the EHC main accumulators at other plants. The licensee plans to disassemble the accumulators for analysis during the next refueling outage. The licensee believes that the current problem is not related to the previous problem documented in IR 50-321,366/94-13.

The inspectors concluded that operations personnel detected the TCV problem in a timely manner and took appropriate and prudent actions. It was also concluded that the coordination between operations, GE, and maintenance was effective.

g. Intake Structure Service Water Problems

Unit 1 experienced PSW fouling problems on August 18, when the turbine building and control building chillers began tripping. The following day, maintenance cleaned the strainers to the computer room air conditioners that had tripped and would not restart. Algae and moss were found to be fouling the strainers. Other Unit 1 plant components, including the RBCCW heat exchanger, turbine building chillers, control building chillers, main turbine lube oil coolers, and main generator hydrogen coolers, were affected by the PSW fouling. The 1A RBCCW heat exchanger was found by maintenance to be about 30% plugged with small sticks, leaves, moss, and algae. The licensee continued to backwash and clean affected strainers and heat exchangers to lessen the severity of the fouling problem. Also, PSW was chlorinated to the maximum amount permissible. The low river water level in conjunction with high ambient temperatures contributed to the accelerated algae and moss growth.

Main generator hydrogen cooling became the most limiting parameter for power generation. Its limiting temperature was 51°C. Unit 1 commenced a power reduction on August 22, due to the inability to maintain the main generator hydrogen temperature below 51°C at 100% RTP. Power was ultimately reduced to approximately 89% RTP. Inspection of a main generator hydrogen cooler 1B identified that the PSW divider plate was broken. This allowed the PSW to bypass the tubes of the hydrogen cooler. The problems with the main generator hydrogen cooling resulted more from the broken divider plate than from PSW fouling. The PSW fouling problems affected only Unit 1.

As a precaution, the licensee performed PSW flow operability tests for the ECCS room coolers and other safety related equipment cooled by PSW. The results of the PSW flow operability tests for RHR, Core Spray, HPCI, and RCIC room coolers as well as all of the EDGs were satisfactory. MCREC was not tested since it was tagged out for cleaning. The inspectors concluded that managements' precautionary measures to test ECCS and other safety related systems cooled by PSW during the fouling problems was good.

An inspection of the river entry area to the intake structure and the intake structure suction pit was conducted by contract divers on July 25. This inspection identified a build up of silt above the acceptance criteria in some locations. The licensee scheduled dredging to be completed within 60 days. On August 23, it was determined that the intake structure pit needed reinspecting due to the ongoing PSW fouling problems. Two divers from a contract company arrived at the site to inspect the intake structure pump pit bottom, take measurements of mud depth, and obtain mud samples.

While performing an inspection on the Unit 2 side of the intake structure, a slack section of the diver's support line entered into the suction of the 2A RHRSW pump. The diver was not able to remove the line from the pump suction. The support line is a composite cord consisting of an air breathing line, a line for determining the depth of the diver, a communication line, and a rope for supporting the other three lines during movement. These four lines are taped together with duct tape at approximately 12 to 18 inch intervals and will not float on water.

The 2A RHRSW pump was in service to support torus cooling for a RCIC surveillance. CR operators had noticed that the RHRSW flow decreased from approximately 4000 gpm to about 1100 gpm. While investigating the cause of the flow reduction, CR personnel received a call from the maintenance personnel observing the diver's work requesting that the 2A RHRSW pump be stopped. This was when operations first learned of the diver's work activity in the intake structure pit. The 2A RHRSW pump was stopped and declared inoperable. The section of the support line caught in the pump's suction remained there. The loose ends of the line were pulled tight and securely fastened at the top of the intake pit. The diver was not injured in the incident.

The inspectors reviewed procedure 52PM-MME-006-OS: Intake Structure Pit Inspection. This procedure stated, in part, that extreme caution must be exercised to not allow the divers or their tools and equipment to approach the suction bell of any pump, that a pre-job briefing by the system engineer will be conducted prior to the performance of diving operations, and to obtain the shift supervisor's permission before starting the inspection. The inspectors determined that these procedural requirements were not followed.

The inspectors interviewed the PMMS Foreman responsible for the contract divers and maintenance management. A discussion concerning the work scope and the use of procedures had taken place between the PMMS foreman and maintenance management prior to the start of work. Poor communications between maintenance management and the job foreman resulted in a failure to implement procedure 52PM-MME-006-OS for the work activity.

The failure to follow procedure during the diving activity in the intake structure pit area is identified as a second example of VIO 50-321,366/95-18-01: Failure to Follow Procedure While Performing Hydrogen Water Chemistry Flow Changes and Intake Structure Inspection Activities.

On August 25, the contract divers reentered the intake structure pit to remove the section of the support line from the 2A RHRSW pump.

An MWO with work instructions was used for this activity. Most of these work instructions were taken from the requirements, precautions/limitations, and prerequisites sections of procedure 52PM-MME-006-0S. The support line was removed from the RHRSW pump with little difficulty. A functional test was performed and the pump was declared operable the same day.

In addition, on August 31, the inspectors were informed by PMMS management that a stop work had been initiated after a basket containing the divers' tools had dropped in the intake structure pit. A knot on the rope had worked loose, allowing the basket to drop. All tools were intact in the basket upon its retrieval. The stop work was initiated to enable licensee management to gain better control of the diver's work activities. A continuous fire watch was instituted to preclude the divers from having to remove their tools via the basket each time they exited the intake structure pit area. Also, new ropes were used for raising and lowering the basket containing the tools. Knots placed in the rope were secured with duct tape.

The inspectors concluded that a lack of clear communications between maintenance and the work foreman contributed to the failure to follow procedure for the divers' work activity in the intake structure pit on August 23.

4. Engineering Activities (37551) (92700) (92903)

   a. EDG Voltage Regulators - Manual/Auto Transfer

   During the licensee's review of the Unit 1 EDG timer logic network design change, engineering personnel identified a problem with the Unit 1 and Unit 2 EDG voltage regulator logic. This review was conducted in an effort to correct previously identified problems with the Unit 1 EDG LOCA/LOSP signal motor operated sequence timers. IFI 50-321,366/94-27-04 documented the inspectors earlier review of these problems.

   During this report period, engineering personnel identified that when the EDG voltage regulators were placed in manual and a LOSP occurred, the following sequence would happen:

   - The undervoltage relays for the respective 4160 V bus would actuate and the voltage regulator would shift to the automatic mode

   - The EDGs would start and come up to speed, with the generator's automatic voltage regulator controlling the voltage; and the EDG output breaker would close onto its respective 4160 V emergency bus.

   - With the 4160 V emergency bus undervoltage no longer sensed, the undervoltage relays would reset. The voltage regulator would then shift to the manual mode due to the mode switch being in the manual position. The voltage level would adjust to the manual set-point demand. The resulting voltage might not be sufficient to carry the bus load demands.

The inspectors were immediately informed of the problem. The licensee informed the inspectors that the surveillance procedures requiring the regulators to be placed in manual would be revised prior to their use.

The inspectors verified the procedures had been temporarily changed. This change cautioned the operators and instructed them to place the voltage regulator in automatic during a LOSP. The licensee now declares the EDG inoperable when the voltage regulator is in manual.

The inspectors reviewed electrical drawings H23811, H23314 through 16 and the EDG surveillance procedures. Based on the reviews and discussions with the licensee, the inspectors noted that the EDGs are routinely operated with the voltage regulator in manual for at least one hour during the monthly and semi-annual surveillances and for at least 24 hours for the 18 month surveillance.

The inspectors concluded that the system engineer's identification of the logic problem was very good. The inspectors also concluded that placing the voltage regulator back in automatic following a LOSP was appropriate. The inspectors noted that, even though the EDG is declared inoperable when the voltage regulator is placed in manual, it will perform its safety function following a LOSP when placed in the automatic mode.

b. 1B EDG High Crankcase Pressure

Licensee personnel from the operations, maintenance and engineering departments performed surveillance test 34SV-R43-002-01, Diesel Generator 1B Monthly Test, on August 28. No crankcase pressure transients were observed. Prior to the test the EDG had been idle for 33 days.

Prior to the replacement of the lube oil cooler, the EDG had tripped on high crankcase pressure after being idle for two weeks. The inspectors concluded that replacing the lube oil cooler corrected the recurring EDG high crankcase pressure tripping problem.

c. Unit 1 Fuel Leak

On August 13, a routine sample analysis of the Unit 1 Main Condenser Pretreatment Off Gas System identified an increase in the gross gamma radioactivity rate of the noble gasses Xe-133, Xe-135, Xe-138, Kr-85, Kr-87, and Kr-88 (Sum of the Sixes). This is an indication of a possible fuel leak. Previous Unit 1 fuel leakage was identified on March 17, 1995, and is documented in IR 50-321,366/95-06. Also, early in 1994, Unit 2 operated at reduced power for several months due to fuel damage caused by debris. The Sum of the Sixes increased from approximately 375 μCi/s to approximately 1085 μCi/s. The chemistry department increased sampling, and operations personnel increased their monitoring frequency, to track the increasing trend. Licensee management contacted personnel in the corporate office fuels group and GE for assistance to evaluate the activity increase.

On August 14, reactor power was reduced to about 55% to begin flux tilt testing to locate the fuel leak. Flux tilt testing was completed on August 18. Engineering personnel and GE confirmed that a small fuel leak existed. Control rods 22-27, 26-27, 26-23, and 26-31 were fully inserted into the reactor core to suppress power in the area of the fuel leak. The control rods 22-27 and 26-27 were later electrically disarmed and placed under an administrative control clearance to track inoperability. Reactor power was slowly increased and 100% RTP was reached on August 22.

The areas of the fuel leak consisted of two first cycle bundles and two thrice-burned bundles. The inspectors conducted a review of core thermal limit data for the previous four months and did not identify any discrepancies. The licensee has not identified the cause of the leak.

The inspectors conducted a review of the gross gamma sample results to assess the Pretreatment Off Gas System's radioactivity changes. The inspectors noted that the highest Sum of the Sixes was approximately 2495 μCi/s prior to the flux tilt testing. After four control rods were inserted to suppress power in the area of the fuel leak, the Sum of the Sixes decreased to approximately 1300 μCi/s, and remained at that level. These values are a very small percentage of the Unit 1 TS 3.7.6 limit, of 240,000 μCi/s. Plant operation was not affected. However, engineering management stated EOC coastdown would begin sooner than anticipated.

The inspectors concluded that the chemistry department and engineering took prompt actions responding to the suspected fuel leak. Licensee management took immediate actions to locate and suppress power in the location of the leak. Coordination between corporate and onsite engineering was good. No discrepancies were identified by the inspectors.

d. Unit 1 Rector Feed Pump Minimum Flow Valves

On August 14, an automatic runback of the recirculation pumps was received while removing the 1B RFP from operation. The runback occurred with the automatic opening of the 1B RFP minimum flow valve. The reactor was at 55% RTP and reactor core flow was at 55%. The core flow decreased to 52% due to the runback. The reactor did not enter the region of potential instability. The runback was reset and flow was returned to 55%.

On August 16, another automatic runback was received while placing 1B RFP in operation. As flow was increased on the 1B pump the flow decreased on the 1A pump. When flow on the 1A pump reached the minimum flow setpoint, the minimum flow valve automatically opened. Reactor water level decreased and the runback occurred. Reactor core flow did not reach the region of potential instability. The runback was reset and flow was restored.

A review by the licensee indicated that both the 1A and 1B minimum flow valves were opening in less then 2 seconds. MWOs 1-95-2106 and 2119 were issued to adjust the valve stroke times, because the fast opening time can cause runbacks. The 1B valve was adjusted to open in 14 seconds and the 1A valve to 30 seconds. The inspectors were informed that these were longest opening times obtainable for the valves.

The inspectors reviewed drawings H-11604, Unit 1 Condensate and Feedwater System, and H-21038, Unit 2 Condensate and Feedwater System. It was noted that the Unit 1 RFP minimum flow valves were hydraulically operated and the Unit 2 valves were air operated. The inspectors discussed the valves with engineering personnel. The inspectors were informed that the Unit 1 valves were originally adjusted to open in 30 seconds and the Unit 2 valves in 150 seconds. The inspectors also reviewed MWO 1-94-0412: Perform 18 month PM on 1A RFP Minimum Flow Valve. The MWO required that the valves be cycled but did not have a stroke time requirement.

The inspectors noted, from these reviews and discussions, the runback problem was applicable to Unit 1 only. The original 30 second opening stroke times for the Unit 1 valves had drifted to less than two seconds. The Unit 1 and 2 valves were cycled for PM purposes without a stroke time requirement.

The inspectors concluded that both runbacks were due to the short opening times of the minimum flow valves. The flow piping is eight inches in diameter, and with rapid opening of the valves, the reactor was deprived of adequate feedwater flow. The plant feedwater system did not respond fast enough to compensate for the flow diversion. Reactor water level decreased to the setpoint for a runback.

The inspectors also concluded that the second runback might not have occurred if the valves short opening time had been corrected following the initial problem. The inspectors noted that this was an example where BOP system or component problems resulted in plant transients. Management's attention to BOP systems that cause plant transients could have been more thorough.

No violations or deviations were identified.

5. Plant Support Activities (71750) (82301)

a. Review of Response to Overt Threats

The inspectors reviewed the licensee's ability to respond to security events with respect to overt threats. The inspectors reviewed the PSP, procedure 80AC-SEC-004-0S: Overt Threats and Civil Disturbances, Revision 0, and procedure 73EP-EIP-005-0S: On-Shift Operations Personnel Emergency Duties, Revision 4. The inspectors noted that emergency event classifications exist for overt threats. The inspectors concluded that the procedures included satisfactory instructions for prompt and correct response and reporting of such events. The procedures provided a clear link between the different departments that would respond to these events. The inspectors discussed operator actions for overt threats with on-shift licensed and non-licensed operators and concluded they were familiar with the required operator actions and duties. The inspectors verified that instructions and checklists for handling overt threat information were available at randomly selected permanent work stations. The inspectors also verified recent operator training included procedure reviews and discussions of required operator actions for overt threats.

The inspectors concluded that training and procedures were satisfactory for prompt and correct response to overt threats.

b. NRC's Participation in Graded EP Exercise

On August 23, the NRC participated in a full participation graded EP exercise. The state, county and local officials were involved with emergency support offices activated. The NRC implemented agency wide procedures as delineated in NUREG-0728: NRC Incident Response Plan, and NUREG-0845: Agency-wide Procedures for the NRC Incident Response Plan. The emergency response centers and emergency response teams were activated. The NRC headquarter's executive team, and the Region II base team and site team responded to the simulated emergency. The Region II Regional Administrator was the Site Team Leader. The site team reported to the site to monitor and evaluate licensee activities. The Site Team Leader assumed the position of Director of Site Operations to assess total response capabilities and oversee NRC activities. Details of the graded exercise are contained in IR 50-321,366/95-15.

No violations or deviations were identified.

6. Exit Interview

The inspection scope and findings were summarized on September 11, 1995, with those persons indicated in paragraph 1 above. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection.

Item Number	Status	Description and Reference
IFI 50-366/95-18-01	Open	Additional Reviews of Unit 2 Manual Scram Due to Condenser Vacuum (paragraph 2.b).
VIO 50-321,366/95-18-02	Open	Failure to Follow Procedure While Performing Hydrogen Water Chemistry Flow Changes and Intake Structure Inspection Activities (paragraphs 2.d and 3.g).

7. Acronyms and Abbreviations

AC - Alternating Current
ALARA- As Low As Reasonably Achievable
BOP - Balance of Plant
CFR - Code of Federal Regulations
CIV - Combined Intercept Valve
CR - Control Room
ECCS - Emergency Core Cooling System
EOC - End of Cycle
EDG - Emergency Diesel Generator
EHC - Electro-Hydraulic Control
EMI - Electromagnetic Interference
EP - Emergency Planning
ERT - Event Review Team
ESF - Engineered Safety Feature
FSAR - Final Safety Analysis Report
GE - General Electric Company
GPC - Georgia Power Company
gpm - gallons per minute
Hg - Mercury
HP - Health Physics
HPCI - High Pressure Coolant Injection
hr - Hour
HSD - Hot Shutdown
I&C - Instrumentation and Controls
IFI - Inspector Followup Item
INPO - Institute of Nuclear Power Operations
IR - Inspection Report
ISI - Inservice Inspection
Kr - Krypton
LOCA - Loss of Coolant Accident
LOSP - Loss of Offsite Power
μCi/s- Microcurie per Second
MCREC- Main Control Room Environmental Control
MG - Motor Generator
mrem - Milli-Roentgen Equilivant Man
MSIV - Main Steam Isolation Valve
MSL - Main Steam Line
MWe - Megawatts Electric

MWO - Maintenance Work Order
NRC - Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation
P&ID - Piping and Instrumentation Diagram
PCIS - Primary Containment Isolation System
PCIV - Primary Containment Isolation Valve
PEO - Plant Equipment Operator
PM - Preventive Maintenance
PMMS - Plant Modifications and Maintenance Support
psig - pounds per square inch
PSP - Plant Security Plan
PSW - Plant Service Water System
RAS - Required Action Statement
RBCCW- Reactor Building Closed Cooling Water
RCIC - Reactor Core Isolation Cooling System
rem - Roentgen Equivalent Man
RFP - Reactor Feed Pump
RFPT - Reactor Feedwater Pump Turbine
RHR - Residual Heat Removal
RPS - Reactor Protection System
RTP - Rated Thermal Power
RWCU - Reactor Water Cleanup
SCFM - Standard Cubic Feet per Minute
SOS - Shift Operations Supervisor
SPDS - Safety Parameter Display System
TCV - Turbine Control Valve
TS - Technical Specifications
V - Volts
VAC - Volts Alternating Current
VDC - Volts Direct Current
VIO - Violation
Xe - Xenon
" - Inches