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

Docket Nos. 50-424, 50-425
License Nos. NPF-68, NPF-81

APR 16 1991

Georgia Power Company
ATTN: Mr. W. G. Hairston, III
Senior Vice President -
Nuclear Operations
P. O. Box 1295
Birmingham, AL 35201

Gentlemen:

SUBJECT: NRC INSPECTION REPORT NOS. 50-424/91-05 AND 50-425/91-05

This refers to the inspection conducted by Brian Bonser of this office on February 24 - March 23, 1991. The inspection included a review of activities authorized for your Vogtle facility. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed inspection report.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observation of activities in progress.

Within the scope of the inspection, no violations or deviations were identified.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and the enclosure will be placed in the NRC Public Document Room.

Should you have any questions concerning this letter, please contact us.

Sincerely,

Alan R. Herdt

Alan R. Herdt, Chief
Reactor Projects Branch 3
Division of Reactor Projects

Enclosure:
NRC Inspection Report

cc w/encl: (See page 2)

cc w/encl:
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DETAILS

1. Persons Contacted

Licensee Employees

*H. Beacher, Senior Plant Engineer
J. Beasley, Manager Operations
S. Bradley, Engineering Supervisor
*S. Chesnut, Manager Technical Support
*C. Christiansen, Safety Audit and Engineering Group Supervisor
C. Coursey, Maintenance Superintendent
*[illegible]. Greene, Assistant General Manager Plant Support
*H. Handfinger, Manager Maintenance
M. Hobbs, I&C Superintendent
*K. Holmes, Manager Training and Emergency Preparedness
*M. Horton, Manager Engineering Support
*D. Huyck, Nuclear Security Manager
*W. Kitchens, Assistant General Manager Plant Operations
*R. LeGrand, Manager Health Physics and Chemistry
*G. McCarley, Independent Safety Engineering Group Supervisor
*M. Sheibani, Nuclear Safety and Compliance Supervisor - Acting
*W. Shipman, General Manager Nuclear Plant
*C. Stinespring, Manager Plant Administration
*J. Swartzwelder, Manager Outage and Planning Operations

Other licensee employees contacted included technicians, supervisors, engineers, operators, maintenance personnel, quality control inspectors, and office personnel.

Olgethorpe Power Company Representative

*E. Toupin

NRC Resident Inspectors

*B. Bonser
*D. Starkey
*P. Balmain

*Attended Exit Interview

An alphabetical list of acronyms and initialisms is located in the last paragraph of the inspection report.

2. Plant Operations - (71707)

a. General

The inspection staff reviewed plant operations throughout the reporting period to verify conformance with regulatory requirements, Technical Specifications, and administrative controls. Control logs, shift supervisors' logs, shift relief records, LCO status logs, night orders and standing orders, lifted wires and jumper logs, and clearance logs were routinely reviewed. Discussions were conducted with plant operations, maintenance, chemistry, health physics, engineering support and technical support personnel. Daily plant status meetings were routinely attended.

Activities within the control room were monitored during shifts and shift changes. Actions observed were conducted as required by the licensee's procedures. The complement of licensed personnel on each shift met or exceeded the minimum required by TSs. Direct observations were conducted of control room panels, instrumentation and recorder traces important to safety. Operating parameters were observed to verify they were within TS limits. The inspectors also reviewed DCs to determine whether the licensee was appropriately documenting problems and implementing corrective actions.

Plant tours were taken during the reporting period on a routine basis. They included, but were not limited to, the turbine building, the auxiliary building, electrical equipment rooms, cable spreading rooms, NSCW towers, DG buildings, AFW buildings and the low voltage switchyard.

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

The inspectors verified that the licensee's health physics policies/procedures were followed. This included observation of HP practices and review of area surveys, radiation work permits, postings, and instrument calibration.

The inspectors verified that the security organization was properly manned and security personnel were capable of performing their assigned functions; persons and packages were checked prior to entry into the PA; vehicles were properly authorized, searched, and escorted within the PA; persons within the PA displayed photo identification badges; and personnel in vital areas were authorized.

b. Unit 1 Summary

The unit began the period operating at full power. On February 25, power was reduced to 90% for replacement of heater drain pump A due to high vibration. Power was reduced further on February 28 to approximately 80% due to potential electrical grid instabilities resulting from the West Macintosh 500 KV line being out of service. Power was returned to 90% on March 5, repairs to HDP A were completed and power was increased to 99%. On March 6, an ESF actuation occurred due to a voltage transient on the B train dc system that resulted in a control room ventilation and containment ventilation isolation. The ESF actuation had no effect on power operations. The unit operated at full power through the end of the report period.

c. Unit 2 Summary

The unit began the period in Mode 3 following an automatic reactor trip on Overtemperature Delta T due to a circuit card failure. On February 24, criticality was achieved; the unit entered Mode 1 and the main generator was tied to the grid. The unit reached 100% power on February 25 and operated at full power until March 16. On March 16, the unit was shutdown for a planned outage to install a main turbine EHC modification and to repair a leak on a SG #4 handhole. The unit achieved criticality and the generator was tied to the grid on March 24.

d. Unplanned Emergency Diesel Generator Start

On March 21, during performance of procedure 14608-1, SSPS Slave Relay K601 Train A Test Safety Injection, an unplanned start of the 1A EDG occurred. Personnel performing the surveillance had incorrectly depressed the "Test SI" push button instead of the "SI OR U/V Test Output Switch 1A & 1C" as called for in the procedure. The personnel involved had walked through the procedure prior to its performance and during the walk through had incorrectly identified which test push button was to be used. Three licensed personnel were present during the walkdown and none noticed that the panel pushbutton which they intended to use was not the one described in the procedure. This event was not considered to be reportable since the EDGs are not, by definition, ESF equipment. However, the licensee did write a DC, 1-91-079, which will require a formal disposition as to reportability and corrective actions. The licensee stated that the specific procedure step will be reworded and that a broadness review of similar procedures will be performed to eliminate possible future misinterpretations. The resident inspectors consider this event to be an example of operator inattention to detail in following a plant procedure.

e. Unit 2 SG Secondary Side Access Handhole Leak Repair

During recent Unit 2 operation, a leak developed around the seating surface of a secondary side handhole on SG #4. The leak became apparent when the Containment Air Cooler Condensate Leak Detection system was alarming continuously. An analysis of the leak off determined the leak was not from the RCS. Walkdowns in containment determined that the leak was from a secondary side handhole close to the tube sheet on the #4 steam generator. Calculations on the magnitude of the leak ranged up to 4 gpm.

The licensee developed a repair scheme which called for shutting down the unit to Mode 3 (Hot Standby) and pressure injection of a sealant compound into the handhole cover plate. This repair scheme was intended to seal the void between the handhole cover and the SG shell. Injection of the sealant compound involved drilling holes into the handhole cover plate. The licensee's safety evaluation of the leak repair technique involved the assessment of two issues: an evaluation of the structural aspects of the SG shell to determine that SG integrity was maintained; and the resultant effect on secondary side chemistry following introduction of the sealant compound. The inspectors reviewed the licensee's temporary modification request and 10 CFR 50.59 safety evaluation and were satisfied the licensee was taking a safe and conservative approach.

Over the weekend of March 16, Unit 2 was shutdown to Mode 3 to perform the leak repair. The first attempt to stop the leak failed. Following this attempt, the licensee discovered that the sealant used in the effort was inadequate for the temperature and pressure involved. Apparently, at normal operating temperature and pressure, the sealant turned to powder. The licensee in preparing the Temporary Modification Request failed to adequately consider the effects of temperature. A second attempt at injecting sealant, using a metal clamp around the outside diameter of the flange and a different sealant, also failed to stop the leak. On March 20, Unit 2 was taken to Mode 5 (Cold Shutdown). The #4 steam generator was drained and the leaking flange was removed for inspection and repair. At the end of the inspection period the repairs had been comp ted and the unit was returning to power.

f. Technical Specification Clarifications

During this inspection report period, the inspectors noted three occasions where the licensee found it necessary to clarify or evaluate TS for continued conduct of operations. These three evaluations were all associated with the leak on the Unit 2 #4 steam generator. In all three cases, the inspectors assessed the licensee's clarifications as safe and conservative. The inspectors paid particular attention to these interpretations because they all involved weighing safety and economic factors. The conservatism of the licensee's interpretations have been questioned in the past.

The first clarification involved the Containment Air Cooler Condensate Leak Detection system being in constant alarm (TS 3.4.6.1). The question was whether the constant alarm rendered this portion of the RCS leak detection system inoperable. The licensee's conclusion was that the alarm function is not required for the system to perform its function. The system was operable as long as it was capable of being used for leakage detection. The licensee initiated a surveillance to calculate leak rate from air cooler condensate once per shift.

The second decision involved a judgement on whether to go to Mode 4 (Hot Shutdown) or Mode 5 (Cold Shutdown) for removal and/or repair of the SG handhole. In Mode 4, the Containment Integrity TS was still applicable. With the potential removal of the handhole cover, the question arose whether Containment Integrity would be violated if the plant was still in Mode 4. After considering this and other factors, the licensee decided to go to Mode 5.

The third clarification, applicable in Mode 5 only, involved a footnote in TS 3.4.1.4.1 which requires a RCP not be started unless secondary water temperature of each SG is less than 50 degrees F above each RCS cold leg temperature. The licensee wanted to start a RCP with no RCPs running (in Mode 5) after securing the only running RCP upon receiving a high vibration alarm (which later proved false). The basis for this TS is to prevent RCS pressure transients through energy addition from the secondary side. With SG #4 drained for the handhole repair a question arose as to applicability of the TS to the empty SG. The licensee performed a thermodynamic analysis of air and water and concluded it was acceptable to start a RCP with a SG drained.

g. ESF Actuations - Containment Ventilation Isolation And Control Room Isolation

On March 6, personnel were troubleshooting an electrical ground in the Unit 1 125 vdc switchgear. As a part of this process, the 1B battery output breaker, 1BD1-01, was opened creating a disconnect between the battery chargers and the batteries. When the battery chargers began making variable pitched noises and the indicator light on the bus began to fluctuate in intensity the equipment operator reclosed the breaker. In the control room a large number of annunciators were recieved including indications that a containment ventilation isolation and control room isolation had occurred. All valves and dampers actuated as designed.

The licensee's investigation determined that when circuit breaker 1BD1-01 was opened one of the two battery chargers (1BD1CA) experienced voltage fluctuations from 90 to 140 volts. A protection circuit in inverter 1BD1I12 automatically shutdown inverter operation when voltage from the chargers went below 105 volts. When the inverter tripped, power was lost to various radiation monitors and other equipment that had annunciated in the control room. This caused the radiation monitors to send ESF actuation signals upon loss of power. It was found that the voltage fluctations in battery charger 1BD1CA could be stopped when a one of its six control circuit boards was replaced. The licensee could not explain this unusual condition. A search for a specific failure is continuing. The licensee will report this event in LER 424/91-04.

No violations or deviations were identified.

3. ESF System Walkdown (71710)

On March 19, the inspectors completed a system walkdown of both trains of the Unit 1 Containment Spray System. The purpose of the walkdown was to determine whether the system lineup procedure, Containment Spray System Alignment, 11115-1, Rev. 5, agreed with the plant piping and instrumentation diagram, 1X4DB131, Rev. 22 and to identify equipment conditions and items that might degrade plant performance.

Material condition of those areas inspected was good and nothing was observed which might affect system operability. However, several discrepancies were noted regarding labeling of components. Specifically, two valves were missing plastic identification tags, the wording on seven valve identification tags did not exactly match the valve description in the system alignment procedure, and all twelve electrical breaker ID tags differed from the alignment procedure written description. These labeling discrepancies were discussed with the licensee and corrective action will be taken. The inspectors had no other concerns regarding this Containment Spray System walkdown.

No violations or deviations were identified.

4. Surveillance Observation (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, 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, equipment was calibrated, prerequisites were met, tests were conducted according to procedure, test results were acceptable and systems restoration was completed.

Listed below are surveillances which were either reviewed or witnessed:

Surveillance No.	Title
11121-C	Containment Coolers Condensate Collection Calculation
14546-1	Turbine Driven Auxiliary Feedwater Pump Operability Test
14553-2	ESF Room Cooler And Safety Related Chiller Flow Path Verification
14980-1	Diesel Generator Operability Test (6 month fast load test)
14980-2	Diesel Generator Operability Test
28911-2	Seven Day Battery Inspection And Maintenance

a. Main Feedwater Regulating Valves And Bypass Valves Testing

During the licensee's review of Generic Letter 89-19, "Safety Implication of Control Systems in LWF Nuclear Power Plants", it was identified that the MFRVs and BFRVs, according to Westinghouse, are credited in the safety analysis as a backup to the Feedwater Isolation Valves. Termination of main feedwater flow to a faulted steam generator is assumed in the steam line break and feed line break analyses in order to limit the RCS cooldown and mass release from the break. As a result, the licensee added the MFRVs and BFRVs to the active valve list in the FSAR and included them in the Inservice Testing Program. When the Unit 1 active list, IST program, and TS were originally developed the MFRVs and BFRVs were deliberately excluded because it was thought that they were not required by the safety analyses.

To date, the Unit 1 BFRVs and the Unit 2 MFRVs and BFRVs have been tested with satisfactory results. The only remaining valves are the Unit 1 MFRVs which will not be tested within the time requirements now established in the testing program (MFRVs can only be tested with the plant shutdown).

Due to the inability to stroke test the MFRVs at power, the resident inspectors requested that the licensee justify the capability of the MFRVs to close within the specified time until the plant is in a mode in which the valves can be tested. The licensee, using completed ESF Response Time Summation procedures and I&C loop calibration procedures, obtained data which included times for the sensors, SSPS processing and closure times for the MFRVs. The response times for each of the MFRVs was calculated to verify that they could meet the feedwater isolation response time requirements and the inservice testing requirements. All the calculations were within the specified time requirements.

Once the need for testing of these valves was identified, the licensee took appropriate action to add them to the IST program, test the valves if possible, and address the safety issue on the Unit 1 MFRVs.

No violations or deviations were identified.

5. Maintenance Observation (62703)

During this inspection period, a maintenance team inspection (MIT) was conducted at Vogtle by inspectors from Region II and NRR. The results of that comprehensive inspection will be documented in report 50-424,425/91-03.

No violations or deviations were identified.

6. Review of Licensee Reports (90712)(92700)

The below listed Licensee Event Reports were reviewed to determine if the information provided met NRC requirements. The determination included: adequacy of description, verification of compliance with TS and regulatory requirements, corrective action taken, existence of potential generic problems, reporting requirements satisfied, and the relative safety significance of each event.

a. (Closed) 50-425/90-03, Rev. 0, "Trip Of Heater Drain Pump Results In Exceeding The Reactor Power License Limit."

Reactor power was reduced to 90% of rated thermal power and was maintained at that power until previously scheduled maintenance on the heater drain pump was completed. The manual actuation pin for the HDT high level dump valve was disengaged and the valve was returned to automatic operation. The pins were modified so that they are now restrained in the automatic position. Licensed operators were trained during a subsequent requalification class on the conditions that led up to and caused the over power event.

b. (Closed) 50-424/90-20, Rev. 0, "Personnel Error Leads To A Technical Specification Violation."

The GPC electrician and foreman involved were counseled regarding the importance of attention to detail. The Maintenance Manager sent a memo to other appropriate personnel describing this event and the need for adequate reviews. Battery cell #35 was designated a pilot cell, which required weekly testing and should allow future problems with cell #35 to be identified sooner. Finally, battery procedures were reviewed and revised to simplify data recording and to eliminate duplication.

c. (Closed) 50-425/90-12, Rev. 0, "Personnel Errors Load To Containment Spray Pumps' Deactivation."

The SS who approved the clearance to remove the containment spray pump from service was counseled regarding the importance of accuracy in reviewing clearances related to equipment required to be operable per TS. The Reactor Operator was counseled regarding the importance of maintaining a questioning attitude in the performance of his duties. A copy of this LER was included in the Operations Reading Book and was reviewed during a subsequent operator requalification cycle.

d. (Open) 50-425/91-03, Rev. 0, "Diesel Generator Failures May Have Resulted In Loss Of Ability To Mitigate Accident Consequences."

The K4 transfer relays for both the 2A and 2B DGs were replaced and both DGs were demonstrated to be operable. The transfer relay contacts on DG 1A were tested and no problems were found. The K4 transfer relay was replaced on DG 1B due to a somewhat higher resistance across contacts 1 and 7. Furthermore, each DG has been instrumented to measure voltage drop during paralleling operation. No abnormal readings were observed. Testing will continue on the 2A DG in an effort to identify the root cause of the failure. If the licensee determines a defective cause of the failure, a supplemental LER will be submitted. This LER will remain open pending further developments in the licensee's investigation.

No violations or deviations were identified.

7. Followup (92701,92702)

a. (Closed) Part 21 Report, 50-424, 425/91-02, "Cooper Energy Services Potential Defect With EDG Starting Air Admission Valve."

Energy Services Group of Cooper Industries, in a letter to GPC dated July 31, 1990, recommended a plan of action to address the valve sticking problem. GPC subsequently completed all recommended work for valves in service on all Unit 1 and Unit 2 EDGs. Additionally, appropriate maintenance procedures were revised to require that all air start valves in the warehouse be modified prior to installation on a EDG.

b. (Closed) VIO 424,425/90-20-01, "Inadequate Diesel Generator Procedure Resulting In Violation Of TS 6.7.1a."

The licensee responded to the violation in correspondence dated November 15, 1990. Corrective actions included briefing on-shift operations personnel regarding the correct methods for shutting down a diesel generator after an emergency start; additional training incorporated into licensed operator requalification; and revision of plant procedures 13145-1 and 2, "Diesel Generators", to provide guidance on actions to take concerning shutting down the diesels after emergency starts. Based on a review of the licensee's completed corrective actions this violation is closed.

8. Exit Meeting

The inspection scope and findings were summarized on March 22, 1991, with those persons indicated in paragraph 1. The inspector described the areas inspected and discussed in detail the inspection findings listed below. No dissenting comments were received from the licensee. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection.

9. Acronyms And Initialisms

BFRV	Bypass Feed Regulating Valve
DC	Deficiency Cards
dc	Direct Current
EDG	Emergency Diesel Generator
EHC	Electro-Hydraulic Control
ESF	Engineered Safety Features
FSAR	Final Safety Analysis Report
HDP	Heater Drain Pump
HP	Health Physics
IST	Inservice Test
KV	Kilo-Volts
LER	Licensee Event Reports
MFRV	Main Feed Regulating Valve
RCS	Reactor Coolant System
RCP	Reactor Coolant Pump
SG	Steam Generator
SI	Safety Injection
TS	Technical Specification
UV	Undervoltage

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

5-1013

JAN 11 1991

Docket Nos. 50-424 and 50-425
License Nos. NPF-68 and NPF-81

Georgia Power Company
ATTN: Mr. W. G. Hairston, III
Senior Vice President -
Nuclear Operations
P.O. Box 1295
Birmingham, AL 35201

Gentlemen:

SUBJECT: VOGTLE SPECIAL TEAM INSPECTION AND NOTICE OF VIOLATION (NRC INSPECTION REPORT NOS. 50-424/90-19 AND 50-425/90-19)

This refers to the inspection conducted by an NRC Special Inspection Team on August 6 through 17, 1990. The inspection included a review of activities authorized for your Vogtle facility. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed inspection report.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observation of activities in progress.

Based on the results of this inspection, certain of your activities appeared to be in violation of NRC requirements, as specified in the enclosed Notice of Violation (Notice).

Although the inspection concluded that the facility was operate in a safe manner in accordance with the requirements of the operating license, we are concerned that there were several operational policies and programs where weaknesses were identified. As part of your response to the violations identified in the enclosed Notice, you are also requested to address each of the weaknesses listed in the inspection summary.

You are required to respond to this letter and Notice and should follow the instructions specified in the enclosed Notice when preparing your response to the violations. In your response, you should document the specific actions taken and any additional actions you plan to prevent recurrence. After reviewing your response to this Notice, including your proposed corrective actions and the results of future inspections, the NRC will determine whether further NRC enforcement action is necessary to ensure compliance with NRC regulatory requirements.

JAN 1991

SENIOR V.P.

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Additionally, you should respond to each of the operational weaknesses identified within the report. (These weaknesses are specifically annotated in the Inspection Summary.) The response should address your analysis of the significance of the weaknesses and your actions to ensure that these operational practices do not evolve into items of non-compliance or reduce the margin of safety for the plant.

In accordance with Section 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be placed in the NRC Public Document Room.

The responses directed by this letter and the enclosed Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. No. 96.511.

Should you have any questions concerning this letter, please contact us.

Sincerely,

James L. Milhoan for
Stewart D. Ebneter
Regional Administrator
Region II

Enclosures:
1. Notice of Violation
2. Inspection Report 50-424/90-19;
   50-425/90-19

cc w/enclosures:

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cc w/enclosures (continued):

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State of Georgia

ENCLOSURE 1

NOTICE OF VIOLATION

Georgia Power Company
Vogtle Electric Generating Plant
Units 1 and 2

Docket Nos. 50-424 and 50-425
License Nos. NPF-68 and NPF-81

During an NRC inspection conducted on August 6 through 17, 1990, violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C (1990), the violations are listed below.

A. Technical Specification 3.6.3 requires that the containment isolation valves (CIVs) be operable in Modes 1, 2, 3, and 4. With one or more of the CIVs inoperable, at least one isolation valve must be maintained operable in each affected penetration that is open and the inoperable valves must be restored to the operable status within 4 hours or be in Hot Standby within the next 6 hours and in Cold Shutdown within the following 30 hours.

   Contrary to the above, on August 7, 1990, the NRC identified that CIVs 2HV-2792A, 2HV-2792B, 2HV-2791B, and 2HV-2793B were opened and, thus, inoperable during surveillance testing of the hydrogen monitor system for a total of 18 hours and 47 minutes on Unit 1 while in Mode 1 and 21 hours and 11 minutes on Unit 2 while in Mode 1 without complying with the limiting condition for operation (LCO) action statement. (50-424/90-19-02; 50-425/90-19-02)

   This is a Severity Level IV violation (Supplement I).

B. Technical Specification 4.2.5.3 requires that the reactor coolant system (RCS) flow rate be determined by precision heat balance before operation above 75 percent of rated thermal power. Furthermore, this specification requires that, within 7 days prior to performing the RCS flow measurement, the instrumentation used for performing the precision heat balance shall be calibrated.

   Contrary to the above, the licensee failed to calibrate, within seven (7) days prior to use, the instrumentation used during the performance of the precision heat balances required by TS 4.2.5.3 and performed on April 23, 1990. (50-424/90-19-01; 50-425/90-19-01)

   This is a Severity Level IV violation (Supplement I).

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Pursuant to the provisions of 10 CFR 2.201, Georgia Power Company is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555, with a copy to the Regional Administrator, Region II, and, if applicable, a copy to the NRC Resident Inspector within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. If an adequate reply is not received within the time specified in this Notice, an order may be issued to show cause why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

FOR THE NUCLEAR REGULATORY COMMISSION

James L. Milhoan for
Stewart D. Ebneter
Regional Administrator

Dated at Atlanta, Georgia
this 11 day of Jan. 1991

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

Report No.: 50-424/90-19 and 50-425/90-19

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

Docket Nos.: 50-424 and 50-425 License Nos.: NPF-68 and NPF-81

Facility Name: Vogtle Electric Generating Plant, Units 1 and 2

Inspection Conducted: August 6-17, 1990

Team Members:

Ron Aiello - Resident Inspector, Vogtle
Morris Branch - Senior Resident Inspector, Watts Barr
Robert E. Carroll, Jr. - Project Engineer, DRP, Region II
Larry Garner - Senior Resident Inspector, Robinson
Neal K. Hunemuller - Licensing Examiner, NRR
Larry L. Robinson - Investigator, OI, Region II
Robert D. Starkey - Resident Inspector, Vogtle
Craig T. Tate - Investigator, OI, Region II
Peter A. Taylor - Reactor Inspector, DRS, Region II
McKenzie Thomas - Reactor Inspector, DRS, Region II
John D. Wilcox, Jr. - Operations Engineer, NRR

Team Leader: Chris A VanDenburgh 12/19/90
Chris A. VanDenburgh, Section Chief
Division of Reactor Inspections and Safeguards
Office of Nuclear Reactor Regulation

Approved by: Luis A. Reyes 1/2/92
Luis A. Reyes, Director
Division of Reactor Projects
Region II

9102110081

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INSPECTION SUMMARY

Recent activities which have occurred at the Vogtle Electric Generating Plant (VEGP) have raised concerns within the Nuclear Regulatory Commission (NRC) as to the ability and the determination of the licensee to operate the facility in a safe manner. To address this concern, the NRC performed a special team inspection to determine if the licensee operates the facility in accordance with approved procedures and within the requirements of the facility's operating license. In addition to the occurrence of specific operational events at VEGP, NRC concerns regarding the safe operation of the facility were heightened with the receipt of several allegations relating to operational activities at VEGP. The combination of the facts and circumstances associated with the operational events and the allegations warranted the immediate initiation of special inspection activities.

Specifically, the inspection objectives were to:

1) Assess the operational philosophy, policy, procedures and practices of the facility's operating staff and management regarding operational safety.

2) Determine the technical validity and safety significance of each of the allegations and their impact on the safe operation of the facility.

These inspection objectives were accomplished by the use of two inspection teams--an operations followup team and an allegations followup team. The efforts of these two inspection teams were closely coordinated; however, they independently pursued the objectives outlined above.

The operations followup team monitored control room activities on a 24-hour basis in order to: (1) evaluate the operational philosophy, policies, procedures, and practices of the operating staff and management and (2) determine if the plant was being operated in a safe manner in accordance with the facility's operating license. The results of this effort are set out in this inspection report.

The allegations followup team examined the technical validity and safety significance of each of the allegations. In addition, with the assistance of the OI staff, this team interviewed members of the plant staff in order to determine (1) their personal involvement and knowledge of the specific allegations and (2) their practice and understanding of the station operational policies. These interviews were transcribed. Although an OI investigator was assigned to the inspection team to assist during the transcribed interviews, this inspection was not an OI investigation of the alleged violations. The results of the allegations followup team are still under consideration and will be documented in separate correspondence.

Although two violations were identified, the inspection concluded that the facility was operated in a safe manner in accordance with the requirements of the licensee's operating license. In addition, there were several operational practices where weaknesses were identified.

The specific observations and conclusions of the operations followup team are detailed in the inspection report; however, the bases for these overall conclusions are summarized below.

Technical Specifications

The inspection identified two instances in which the licensee violated the requirements of the Technical Specifications.

1) The licensee indicated that the limiting condition for operation (LCO) for TS 3.6.3, "Containment Isolation Valves," did not require the containment isolation valves for the hydrogen analyzer system to remain closed during Modes 1 through 4. The inspection identified Violations 50-424/90-19-02 and 50-425/90-19-02 in this area. (Section 2.2.1.1)

2) The licensee indicated that the surveillance requirements of TS 4.2.5.3, (reactor coolant system precision heat balance flow measurement) did not require the calibration of all the instrumentation used in the performance of the precision heat balance within seven days of performing the heat balance. The failure to perform the calibration of all the instruments used during previous performances of the precision heat balances had resulted in the incorrect calculation of the RCS flow during the period of April 23 through May 21, 1990. The failure to accurately calculate the RCS flow was due to the failure to correctly perform the surveillance requirements of TS 4.2.5.3. The inspection identified Violations 50-424/90-19-01; 50-425/90-19-01 in this area. (Section 2.1.1.2)

Operational Policies and Practices

The inspection identified several instances of operational policies and practices where there were weaknesses. Specifically:

1) The licensee's method for TS interpretations allowed the operations manager to be solely responsible for the approval and distribution of the interpretations. The inspection team was concerned that the intent of the TS may be changed by the interpretations without an interdepartmental review and approval of the interpretations, such as would be provided by a plant review board (PRB) review. (Section 2.1.1.1)

2) The licensee's method for interdepartmental review of procedures appeared to rely on the procedure writer's judgment or another department's request. As evidenced by the lack of

an Operations Department review of Surveillance Procedure 24551-2, "Containment Hydrogen Monitor Analog Operability Test and Channel Calibration," this methodology had not ensured that all procedures that affect the Operations Department receive that department's review and concurrence. The inspection team concluded that the licensee's method of performing intra- and interdepartmental reviews of procedures needed improvement. (Section 2.1.1.6)

3) The licensee indicated that the LCO action requirements of TS 3.7.8, "Snubbers," allowed voluntary entry into the LCO for the performance of snubber modifications (i.e., replacement with fixed struts). The licensee's voluntary entry into the LCO (during modes when the snubbers were required to be operational) was performed as an operational convenience and not in conjunction with other pre-planned testing or maintenance. In addition, the method used for the nuclear service cooling water (NSCW) modifications resulted in an unnecessary reduction in the availability of the engineered safety features equipment. These voluntary entries into LCOs were not necessary and were performed in order to reduce the scope of the subsequent refueling outage. (Section 2.1.1.4)

4) The licensee indicated that the LCO for TS 3.0.3, "Shutdown Actions," allowed a total of seven hours to achieve hot standby and that a reduction in reactor power was not required until three hours after entry of the LCO. This position was based on their ability to go from Mode 1 to Mode 4 (hot standby) within four hours. (Section 2.1.1.3)

5) The licensee's method of certifying the qualifications for plant equipment operators (PEOs) was not correctly performed. The training evaluator delegated the responsibility for evaluating performance of trainee PEO rounds to a qualified PEO. The evaluator (without discussions with the qualified PEO) certified that the rounds were satisfactorily completed based on the qualified PEO's initials, even though the qualified PEO had not observed the performance of the trainee's rounds. In addition, the licensee had not conducted a management review of the implementation of the on-the-job training for PEOs. (Section 2.1.3.2)

6) The licensee's method of identifying the actual expectations for plant equipment operators involving the minimum acceptable performance of general inspections was neither well defined in procedures nor, in some instances, by on-the-job training (OJT). (Section 2.2.6)

7) The licensee's method of authorizing excess overtime in the Operations Department was considered a weakness because of the lack of recent work history information, frequent "after the fact" authorization of excess overtime, and the potential

conflicting responsibilities of the authorizing official. The inspection team also concluded that excess overtime may have been performed by certain individuals. In addition, the non-supervisory staffing policy had the potential to result in unbalanced experience levels on the night shifts. (Section 2.1.3.1)

8) The licensee's method of holding periodic mini-safety meetings for Operations Department personnel was not properly fulfilling the administrative procedure requirements. (Section 2.2.4)

9) The licensee's method for implementing the Quality Concern Program had a potential weakness with respect to the method of exit interviews and the assignment of the investigations. (Section 2.1.3.3)

INSPECTION DETAILS

1.0 INSPECTION OBJECTIVES

Recent operational events which have occurred at the Vogtle Electric Generating Plant (VEGP) have raised concerns within the Nuclear Regulatory Commission (NRC) as to the ability and the determination of the licensee to operate the facility in a safe manner. To address this concern, the NRC performed a special team inspection to determine if the licensee operates the facility in accordance with approved procedures and within the requirements of the facility's operating license. In addition to the occurrence of specific events, NRC concerns regarding the safe operation of the facility were heightened with the receipt of several allegations relating to operational activities at VEGP. The combination of the facts and circumstances associated with the operational events and the allegations warranted the immediate initiation of special inspection activities.

A special inspection team comprising staff from the Region II Office and the Office of Nuclear Reactor Regulation (NRR), assisted by staff from the Office of Investigations (OI), was formed to determine the individual validity and collective impact of these concerns and allegations on the safe operation of the facility. The purpose of the inspection was to determine if the licensee operates the facility in a safe manner in accordance with approved procedures and the requirements of the facility's operating license. Specifically, the inspection objectives were to:

1) Assess the operational philosophy, policy, procedures, and practices of the facility's operating staff and management regarding operational safety.

2) Determine the technical validity and safety significance of each of the allegations and their impact on the safe operation of the facility.

These inspection objectives were accomplished by the use of two inspection teams--an operations followup team and an allegations followup team. The efforts of these two inspection teams were closely coordinated; however, they independently pursued the objectives outlined above.

The operations followup team monitored control room activities on a 24-hour basis in order to: (1) evaluate the operational philosophy, policies, procedures, and practices of the operating staff and management and (2) determine if the plant was being operated in a safe manner in accordance with the facility's operating license. The results of this effort are set out in this inspection report.

The allegations followup team verified the technical validity and safety significance of each of the allegations. In addition, with the assistance of the OI staff, this team interviewed members of the plant staff in order to determine (1) their personal involvement and knowledge of the specific allegations and (2) their practice and understanding of the station operational policies. These interviews were transcribed. Although an OI investigator was assigned to the inspection team to assist during the transcribed interviews, this inspection was not an OI investigation into the alleged violations. The results of the allegation followup team review are still under consideration and will be documented in separate correspondence.

In addition to identifying the operations followup team's conclusions and findings, this report identifies two violations and several weaknesses in the licensee's operational policies, programs, and procedures. The specific details and basis for the inspection team's concerns are detailed in the sections that follow and in the Inspection Summary.

2.0 OPERATIONS FOLLOWUP

The operations followup team monitored the control room activities on a 24-hour basis in order to (1) evaluate the operational philosophy, practices, procedures and policies of the operating staff, and (2) determine if the plant was being operated in a safe manner in accordance with the facility's operating license. The inspection team's shift schedule closely coincided with the operating staff's 12-hour shift rotation so that the NRC inspectors could become familiar with the individual operators and their interaction with other operators.

The operations followup team conducted a performance-based evaluation of the Operations Department in order to evaluate the operational philosophy, policies, procedures, and practices of the operating staff and management. The inspection team observed activities directly and held discussions with the operating staff and management during the shift monitoring activities. This effort was not intended to duplicate or substitute for the efforts of the allegations followup team, but was intended to address whether operational philosophy, policies, procedures or practices similar to those addressed by the allegations team were currently being implemented at the station.

The team used the guidance of Inspection Procedure 71707, "Operational Safety Verification," to evaluate if the plant was operated in a safe manner. In addition, the team used the inspection requirements and guidance of Inspection Procedure 71715, "Sustained Control Room and Plant Observation," and observed operational activities conducted by the licensee to evaluate if:

1) Operators were attentive and responsive to plant parameters and conditions.

2) Plant evolutions and testing were planned and properly authorized.

3) Procedures were used and followed as required by plant policy.

4) Equipment status changes were appropriately documented and communicated to appropriate shift personnel.

5) The operating conditions for plant equipment were effectively monitored, and appropriate corrective action was initiated when required.

6) Backup instrumentation, measurements, and readings were used as appropriate when normal instrumentation was found to be defective or out of tolerance.

7) Log-keeping was timely and accurate, and adequately reflected plant activities and status.

8) Operators followed good operating practices in conducting plant operations.

2.1 Operational Philosophy, Policies, Procedures, and Practices

The operations followup team conducted a performance-based evaluation of the eight attributes above and identified several concerns involving the operational philosophy, policies, procedures and practice of the Operations Department at VEGP. These concerns are identified in Sections 2.1.1 (and its subsections) through 2.1.3 (and its subsections).

2.1.1 Implementation of Technical Specification Requirements

The inspection team identified several concerns with respect to the Operations Department's understanding and implementation of the TS requirements. These are detailed in Sections 2.1.1.1 through 2.1.1.6.

2.1.1.1 Review and Approval of TS Interpretations

As part of the control room monitoring activities, the inspection team noted that the licensee had developed and issued approximately 50 interpretations of Technical Specifications. These interpretations responded to specific questions submitted by the licensed operators. The interpretations were issued by the operations manager without the benefit of review or concurrence by any other department or individual. Although the Licensing Department was heavily involved in the original development of the Technical Specifications, it did not review the interpretations. The TS interpretations were discussed in Section 3.11 of Plant Administrative Procedure 10000C, "Conduct of Operations," Revision 18. This procedure described the method for requesting an interpretation and discussed both verbal and written interpretations. The procedure allowed either the shift superintendent, operations manager or unit superintendent to make the initial interpretation. However, the final, written interpretation was signed by the operations manager.

A review of TS 6.4.1 regarding the function and responsibility of the Plant Review Board (PRB) indicated that the PRB was responsible for reviewing those procedures that established plant-wide administrative controls as well as any proposed changes to TS. The PRB review is the review and audit method specified by TS to provide an interdepartmental review of proposed changes to ensure that the intent of the TS is not changed. The TS did not specifically require that interpretations be approved by the PRB. As such, a licensee action, absent PRB review, appears necessary to ensure that the TS interpretations have not and will not change the intent of the TS.

The licensee indicated that, because the operations manager was qualified to interpret the TS based on his experience, additional reviews were not necessary. In addition, during the exit interview described in Section 4 of this inspection report, the licensee indicated that it was undesirable to have any other department or individual review or concur in the Operations Department interpretation of the Technical Specifications. This position was based on the licensee's desire to minimize the involvement of additional personnel to ensure that the licensed operators had the ability to implement the requirements of the Technical Specifications on a timely basis.

The inspection team noted that the method used by the Operations Department to issue TS interpretations (i.e., written answers to written questions) allowed sufficient time to ensure that the answer was correct. The review of these interpretations would not have delayed a response to an immediate operational concern. In addition, the inspection team noted that several of the interpretations were requested as clarifications by the operators and concerned areas that were beyond the routine knowledge of most licensed operators, such as the definition of core quadrants, the required axial flux difference (AFD) target band for flux difference units, and the applicability of TS 3.6.3, "Containment Isolation Valves," surveillance requirements during sampling, venting, draining, or local leak rate testing (LLRT) activities.

The inspection team's review of several sets of TS interpretation manuals indicated that the TS interpretations were not distributed in a controlled manner and that there was no method to ensure that a complete set was available. The inspection team found that the operations manager's and the control room's copies of the interpretations were not identical. The TS interpretation book maintained in the control room contained an interpretation that was issued on August 14, 1988, concerning TS 3.0.3. This specific interpretation was not in the operation manager's interpretation book. In addition, certain TS interpretations contained supporting information that implied NRC concurrence.

The inspection team concluded that having one individual responsible for the approval and distribution of the TS interpretations requested by the licensed operators was a weakness. The lack of an interdepartmental review and approval of the interpretations could result in a change in the intent of the TS.

2.1.1.2 Calibration Requirements for RCS Flow Instruments

During a Plant Review Board (PRB) meeting on August 6, 1990, the inspection team noted that the PRB approved Licensee Event Report (LER) 50-424,425/90-15 concerning failure to calibrate all the instruments used in the reactor coolant system (RCS) flow balance. The LER documented that for Units 1 and 2 the surveillance requirements of TS 4.2.5.3 (RCS precision heat balance flow measurement) had not been properly performed. Specifically, TS 4.2.5.3 required that the RCS flow rate be determined by precision heat balance at least once every 18 months and after each refueling, before operation above 75 percent of rated thermal power. TS 4.2.5.3 required the instrumentation used for performing the precision heat balance to be calibrated within 7 days before performing the heat balance. The precision heat balance flow measurement was performed in accordance with Surveillance Procedures 88014-C, "Reactor Coolant System Flow Measurement," and 88075-C, "Precision Heat Balance."

The July 12, 1990 Quality Assurance audit of the precision heat balance flow measurement surveillance noted an apparent inadequacy involving Surveillance Procedure 88075-C. The surveillance procedure required the calibration of special test instrumentation used for performing the heat balance, but did not require calibration of plant computer points that were used for obtaining input values for feedwater temperatures. The inspection team's discussion with the reactor engineering supervisor determined that the calibration requirement of TS 4.2.5.3 had been interpreted to apply only to special test instrumentation that was installed and removed during each performance of the precision heat balance. Also, while the feedwater temperature computer points were being calibrated on a routine basis, the Operations Department had not historically calibrated the computer points within the 7 day interval specified by TS 4.2.5.3. The Quality Assurance (QA) audit concluded that the interpretation of the calibration requirement was incorrect in not including the feedwater temperature computer points. Therefore, no previous precision heat balance flow measurements had been completed in compliance with the requirements of TS 4.2.5.3.

LER 50-424,425/90-15 was approved by the PRB on August 8, 1990, to meet the 30-day reporting requirement of 10 CFR 50.73. However, the licensee indicated that calibration of equipment other than special test instrumentation was not required by TS 4.2.5.3 and intended to pursue confirmation of the Operations Department's original interpretation of the TS. The LER indicated that the surveillance procedures would be revised to require the calibration of the feedwater temperature computer points within the 7 days before the performance of the precision heat balance. In addition, the licensee reperformed the precision heat balance calculations for both units using estimated values for the feedwater temperatures. These estimated values were based on the average drift indicated by a subsequent calibration of the feedwater temperature computer points. The new calculations of the RCS flow showed the RCS flow rates to be slightly less than the previously calculated flows, but still above the minimum values specified in the Technical Specifications.

The inspection found that the licensee had previously identified that the RCS flow balance had not been performed correctly for another reason. The RCS flow balance was incorrectly performed on April 23, 1990, because the computer points (which the licensee indicated were not required to be calibrated within 7 days of the surveillance) had been incorrectly calibrated during a previous maintenance activity. The inspection team discussed the chronology of events for Unit 1 with the reactor engineer who indicated the following:

- The precision heat balance and RCS flow calculation were performed on April 23, 1990, at approximately 74 percent of reactor power.

- When the reactor power level was increased to approximately 100 percent, the system performance engineer questioned why electric output and turbine first-stage pressure were lower than expected.

- On April 28, 1990, Deficiency Card (DC) 1-90-240 was written when the licensee's investigation revealed that feedwater temperature, as indicated on Proteus computer's final feedwater temperature points (T0418, T0438, T0458, and T0478) were reading approximately 10 degrees Fahrenheit lower than actual. This error was caused by use of the wrong resistance temperature detector (RTD43) curves during calibration of the points under Maintenance Work Order (MWO) 19000042 on January 23, 1990. It was not apparent from the DC that the effects on the RCS flow calculation were considered.

- On April 28, 1990, the feedwater temperature instruments in question were recalibrated under MWO 19002215.

- On May 21, 1990, the Reactor Engineering Group recalculated the RCS flow based on applying a correction to the original feedwater temperature measurements.

The inspection team found that on both occasions the licensee recalculated the RCS flow rates after finding that the precision heat balance flow measurement was incorrectly performed. However, the licensee did not reperform the precision heat balance surveillance procedure to develop the input data for the RCS flow calculation. The inspection team discussed the licensee's basis for not reperforming the RCS flow balances with the responsible staff of NRR and concluded that this position was technically acceptable.

On May 21, 1990, the licensee used a linear interpolation between the wrong feedwater temperature indication and the correct indication to correct the RCS flow calculations performed on April 23, 1990. This correction resulted in a 1.4 percent reduction in the RCS flow calculation (412,822 gpm to 407,294 gpm). On August 14, 1990, the licensee used estimated values for the calibration drift of the feedwater temperature instruments as corrective action for the failure to recalibrate the instruments within seven days of the RCS flow calculation. The estimated values were based on the average drift indicated by a subsequent calibration of the feedwater temperature computer points. This correction resulted in a 1.5 percent reduction in the RCS flow calculation (407,950 gpm to 401,950 gpm). As a result of both corrections, the recalculated RCS flow was 1.5 percent above the minimum value (396,198 gpm) specified in Technical Specification 3.2.5, "DNB Parameters".

Although the surveillance procedure was not required to be reperformed, the inspection team concluded that the failure to perform the calibration of all the instruments used during previous performances of the precision heat balances had resulted in the incorrect calculation of the RCS flow during the period of April 23 through May 21, 1990. The inspection team concluded that the inaccurate calculation of the RCS flow rate was due to the failure to correctly perform the surveillance requirements of TS 4.2.5.3. This violation will be followed as:

VIO 50-424/90-19-01; 50-425/90-19-01, "Failure To Perform Calibrations of Surveillance Requirement 4.2.5.3 Resulting in Incorrect RCS Flow Measurements."

2.1.1.3 Anticipated Actions for TS 3.0.3

The inspection team reviewed the Operations Department's actions with respect to the requirements of TS 3.0.3. TS 3.0.3 requires that, when a limiting condition for operation (LCO) was not met, except as provided in the associated action requirements, action shall be taken within 1 hour to place the unit in a mode in which the specification did not apply by placing it in hot standby within the next 6 hours, in hot shutdown within the following 6 hours, and at least in cold shutdown within the subsequent 24 hours.

The NRC's position regarding TS 3.0.3 is that a 1 hour interval is allowed to prepare for an orderly shutdown before initiating a change in plant operation. This time permits the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the availability of the electrical grid. The time limits specified to reach lower conditions of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the cooldown capabilities of the facility, assuming only the minimum required equipment is operable.

Discussions with the unit superintendent indicated that the unit shutdown actions will not be initiated until 3 hours into TS 3.0.3 and that only minimum preparations will be made within the first hour. The unit superintendent indicated that the Operations Department interpreted the action statement of TS 3.0.3 to allow 7 hours to be in hot shutdown and to accomplish this, the shift can wait for 3 hours after entering the LCO before commencing a shutdown. The only activity required by the operators during the first hour is to retrieve the shutdown procedure. There were no notifications required within the first hour. In addition, the general manager indicated that an orderly, controlled shutdown can be accomplished within 1 hour.

The documentation for 10 previous entries into TS 3.0.3 indicated that the actions discussed in GL 87-09 (i.e., notification of the load dispatcher within the first hour and a controlled shutdown within the next 6-hours) were not fully implemented. Although not required by the licensee's administrative procedures, these previous TS 3.0.3 entries did not indicate that the load dispatcher was notified or that a change in plant operation was initiated.

Specifically, a review of the control room's LCO logs indicated that on December 22, 1987, an entry into TS 3.0.3 was made for a period of 4 hours and 56 minutes. In addition, entry into this TS action requirement did not occur until 42 minutes after discovery of the condition. A review of the reactor operator logs and the chart recorders indicates that a steady-state power level of approximately 99-percent was maintained for the entire time Unit 1 was in a TS 3.0.3 condition on this occasion. Therefore, the inoperable condition actually existed for 5 hours and 38 minutes with the Operations Department management's full knowledge, without initiating a change in plant operation. The inspection team concluded that the licensee's actions with respect to the requirements of TS 3.0.3 were an operational practice that was considered to be a weakness.

2.1.1.4 Voluntary Entry Into TS LCO Action Requirements

During the inspection, the inspection team identified a concern with the licensee's voluntary entry into the limiting condition for operation (LCO) action requirements of TS 3.7.8, "Snubbers," to perform modifications to the snubbers of safety-related systems. These modifications were performed as part of the licensee's snubber reduction program.

Phase II of the Unit 1 snubber reduction program involved the removal of snubbers during power operation. The installation of a rigid, fixed support was required to allow removal of the snubber; however, the licensee removed the snubbers before the installation of the fixed support. The licensee coordinated the snubber modifications on a system basis in order to minimize the length and number of safety system outages required to perform the work. The total number of snubbers removed during this cycle on each of the safety systems with Unit 1 at power was:

RHR Train A	11
RHR Train B	16
CCW Train A	7
CCW Train B	6
NSCW Train A	14
AFW Train C	10

TOTAL	64

The operations manager stated that, after the second Unit 1 refueling outage (1R2), the modifications to the snubbers were done in conjunction with system outages which were required for other preventive or corrective maintenance. Although another licensee employee indicated that this may not have been entirely true for the residual heat removal (RHR) system, the operations manager stated that the majority of the modifications were performed in conjunction with pre-planned system outages.

Although some of these modifications were made when the system was removed from service for other maintenance and testing, the inspection identified that few of the snubber modifications were done jointly with pre-planned system outages. The majority of the snubber modifications were made during a mode when the safety system was required to be operable and there was no other maintenance or testing performed. Specifically, some of the residual heat removal (RHR) Train B snubbers were removed during the time the train was in a system TS LCO for other work activities. However, seven of the nuclear services cooling water (NSCW) Train A snubbers were removed during a system LCO that involved no other work activities. The trains and supported equipment had been secured by the use of the "pull-to-lock" start switches or by positioning the switches to the "stop" position. The equipment was secured in response to the Engineering Department's recommendation that these snubbers were useful in mitigating water hammer effects during closing of a check valve. The remaining snubbers were removed in accordance with the LCO action requirements of TS 3.7.8. During these modifications, no other work activities were in progress which required the system LCO to be in effect at this time.

TS 3.7.8 requires that all snubbers be operable in Modes 1 through 4 and excludes only those non-safety-related snubbers whose failure would have no adverse effect on any safety-related system. The LCO action statement requires repair or replacement of all of the inoperable snubbers within 72 hours and the performance of an engineering evaluation in accordance with TS 4.7.8.g on the attached safety-related system or the associated safety-related system declared inoperable. TS 4.7.8.g defines the engineering evaluation required for those snubbers that are found inoperable. All of the work packages discussed above were completed within the 72 hour action statement of either the system LCO or the snubber LCO of TS 3.7.8.

The licensee's decision to enter the snubber TS LCO action statements for the majority of the work was based upon VEGP interoffice correspondence from M. B. Lackey to W. F. Kitchens, dated August 2, 1987. This correspondence indicated that (1) when the first snubber is removed, TS 3.7.8 should be entered; (2) work packages should be developed so that the work can be completed within the 72 hours allowed by the LCO action statement of TS 3.7.8, and (3) if problems were encountered, the additional 72 hours of the safety-related system's LCO would allow time for resolution.

The inspection team reviewed the safety evaluations for the design change packages (DCPs) associated with snubber reduction on the RHR and NSCW systems (DCP 88-VINC114-0-1 and DCP 89-VIN0047-0-1, respectively). The reason stated for the proposed modifications was to optimize the design and reduce the quantity of snubbers. The long-term effect anticipated was a significant savings in inspection and maintenance costs, in addition to a reduction in personnel radiation exposure over the life of the plant.

The licensee performed an as-low-as-reasonably-achievable (ALARA) review on each work package. In every case, except the RHR system work package, the licensee determined that because of where the piping and supports were located, there was a minimal difference in the expected exposure between performing the work with the Unit operating at full power and the unit shut down. For the RHR system modifications, the RHR piping provided a larger source term (i.e., more radiation exposure) if the work was performed while the RHR train was operating in shutdown cooling because at power the RHR system is secured. However, the inspection team noted that if the modifications were performed when the unit was shut down, only one RHR train would be required to be operating in the shutdown cooling mode. Therefore, the modifications on the secured RHR train could be performed with essentially no difference in exposure than if they were performed with the unit at power.

After discussions with knowledgeable NRR personnel, the inspection team concluded that TS 3.7.8 was not intended to provide action requirements for modifications to snubbers. The LCO for TS 3.7.8 should be entered only when a snubber is removed from service for required testing or maintenance. If the snubber is not returned to service within 72 hours, the associated safety-related system's LCO must be entered. Furthermore, routine, voluntary entry into the action requirements of the LCOs should adhere to the conservative principle that the entry represents a net safety benefit and should be warranted by operational necessity, not just for convenience.

The licensee's removal and replacement of snubbers with fixed struts provided a more reliable piping support system and, therefore, was a safety benefit to the facility. The licensee had evaluated and implemented steps to preclude the potential damage to the associated systems and equipment under modification; however, for NSCW modifications, these steps included removing the entire ESF train from service. This included securing the NSCW train and the following supporting equipment: component cooling water, safety injection, residual heat removal, the chemical and volume control pump, containment coolers, and ESF room coolers. The inspection team was concerned that the removal of this ESF train from service for approximately 40 hours involved an unnecessary reduction in the availability of ESF equipment.

Because the licensee removed the snubbers before installation of the fixed struts, the operability of the associated system was affected. Based upon the time available to plan the modification, the licensee had the ability to verify the effect of the modification on the operability of the associated systems and should have entered the LCO for the system vice the snubber LCO. In addition, the inspection team concluded that the voluntary entries into the action requirements of the LCO (during modes when the system was required to be operational) were performed as operational conveniences and not in conjunction with other required testing or maintenance. These voluntary entries into the snubber LCO (vice the associated system LCO) were performed in order to reduce the scope of the subsequent refueling outage.

Although the snubber reductions resulted in a safety benefit to the facility, the methods used for the snubber modifications (i.e., the removal of snubbers before the installation of the fixed struts) resulted in an unnecessary reduction in the availability of the ESF equipment during the NSCW modifications. Hence, in this respect, the snubber reduction program was an operational practice where a weakness was identified.

2.1.1.5 Implementation of TS Surveillance Requirements

The inspection team reviewed the TS surveillance requirements to ensure that a surveillance procedure had been developed for each requirement. As a result of this review, the inspection team found that a surveillance procedure did not exist for the surveillance requirements of TS 4.7.3.a, "Component Cooling Water System." This TS requires that at least two component cooling water trains shall be demonstrated operable at least once every 31 days by verifying that each valve that is not locked, sealed, or otherwise secured in position is in its correct position. The inspection team determined that, on April 11, 1989, the operations manager had initiated steps to delete Surveillance Procedures 14551-1 and 14551-2 which previously fulfilled the surveillance requirements of TS 4.7.3.a.

These surveillances were last performed on April 4, 1989, for Unit 1, and April 7, 1989, for Unit 2. The licensee indicated that TS 4.7.3.a required verification once every 31 days of only the valves in the component cooling water (CCW) flow path that were not locked, sealed, or otherwise secured in position. The licensee also stated that surveillances were not required for any CCW flow path valves at Vogtle because all CCW flow path valves are included in the Vogtle locked valve program.

The inspection team noted that TS 4.7.3.a did not specifically exclude valves that were not flow path valves as did other surveillance requirements. For example, Surveillance Requirement 4.5.2.b.2 specifically requires position verification of only the flow path valves in the emergency core cooling subsystems (ECCS). In addition, the inspection team noted that the surveillance procedures for other TS surveillance requirements which were written similar to TS 4.7.3.a (i.e., where valves that were not main flow path valves were not excluded) required the verification of valve positions for valves that were not in the main flow path. Specifically, Surveillance Procedures 14552-1 and 14552-2 which incorporate the requirements of TS 4.7.4.a for the nuclear service cooling water (NSCW) specifically required valves that were not in the main flow path to be verified.

Although the surveillance requirement of TS 4.7.3.a does not exclude the valves that are not flow path valves and the term "flow path" is not mentioned in the TS, the team, after discussions with NRR staff, concluded that the licensee correctly interpreted the intent of the surveillance requirement to exclude the valves that are not flow path valves. The inspectors had no further concerns in this area.

2.1.1.6 Interdepartmental Review of Surveillance Procedures

The inspection team reviewed the manner in which the Operations Department reviewed the procedures of other departments. The procedures of interest were those that had a potential to affect the operations of the plant. The inspection team found that the Operations Department did not review Surveillance Procedure 24551-2, "Containment Hydrogen Monitor Analog Operability Test and Channel Calibration," before implementation. Although Administrative Procedure 00051-C, "Procedures Review and Approval," required affected departments to review revisions to, or the deletions of department procedures, the Operations Department failed to review Surveillance Procedure 24551-2. The inspection team could not verify whether the Operations Department had failed to review other Maintenance Department procedures, because the licensee's process for interdepartmental review was conducted informally and was not always documented.

On the basis of this informal process of performing interdepartmental reviews, the team requested that the licensee identify the method used in the past for intra- and interdepartmental reviews of such Maintenance Department procedures as surveillance procedures. This methodology was described and presented to the NRC in the form of interoffice correspondence dated August 28, 1990, from D. E. Gustafson to H. M. Handfinger and titled, "Procedure Reviews."

The determination of the need for interdepartmental reviews was based on whether the procedure called on another department to take action or perform a service, or whether the department expressed a desire for a review. The need for a technical review by the Engineering Department was based on the personal opinion of the procedure writer. Also, for interdepartmental reviews, the procedures were sent to the individual who, in the opinion of the procedure writer, knew the most about the subject of the procedure. In addition, with the exception of integrated leak rate testing (ILRT) procedures, the Operations Department did not review the instrumentation and control surveillance procedures unless specifically asked to review them. The licensee could not indicate how many of the surveillance procedures had received an interdepartmental review.

The inspection team was concerned that the method for interdepartmental review appeared to rely on the procedure writer's judgment or on another department's request. As evidenced by the lack of an Operations Department review of Surveillance Procedure 24551-2, "Containment Hydrogen Monitor Analog Operability Test and Channel Calibration," this methodology has not ensured that all procedures that affect the Operations Department are reviewed and concurred on by that department. Although the licensee indicated that Maintenance Procedure 20022-C, "Mechanical and Electrical Maintenance Procedure Writer's Guide and Review Guidelines," Revision 6, would be revised to provide more specific direction for inter-departmental reviews, the inspection team concluded that the licensee's method of performing intra- and interdepartmental reviews of procedures is a weakness and needs to be improved.

2.1.2 Review of Deficiencies for Unanalyzed Conditions

Deficiency Cards 1-90-299 and 2-90-080 were issued concerning the potential actuation of the emergency diesel generator ground fault relay during a fire in Zone 80. The postulated scenario assumed that a fire in Zone 80 during a loss of offsite power (LOOP) to the Train B emergency bus would result in damage to the unprotected Train A cables, a loss of Train A, and damage to certain non-Class-1E cables which are fed from Train B. The damage would be such that the emergency diesel generator (EDG) Train B neutral overcurrent relay would sense an overcurrent condition and trip the EDG Train B output breaker.

A GPC letter dated July 31, 1990, from W. C. Ramsey to C. C. Miller, indicated that the Train B cables were protected and that Train B equipment and cables required for safe shutdown would not be damaged. Thus, although an unanalyzed ground fault which could separate the EDG from the Train B safety-related bus might occur, the equipment required to achieve and maintain safe shutdown would remain undamaged and the plant configuration would be similar to a station blackout. The letter also indicated that the corrective actions needed to isolate the ground fault and reestablish power to Train B are straightforward and readily accomplished within the time frame previously analyzed for a station blackout. Thus, adequate time is available to provide power to the safety-related equipment required to shut down the plant. The letter concluded that the capability to meet the design basis of the plant is maintained and if this scenario were to occur, it would not be a significant compromise of plant safety and therefore is not reportable per the requirements of 10 CFR 50.72.

The licensee plans to modify the neutral overcurrent relay circuit so that it provides only an alarm function (i.e., it does not trip the EDG output breaker). In the interim, instructions have been given to the operating staff concerning actions to be taken if a fire occurs in Zone 80 simultaneously with a LOOP to the Train B emergency bus. The inspection team asked for additional information concerning what adverse plant effects, if any, might occur during the time required to reenergize Train B from the EDG.

On October 11 and 12, 1990, the licensee reported the results of their engineering analysis of this issue. While the potential for a double fault condition exists, SER Supplements 4 and 8 specifically addressed the potential for "hot shorts" and accepted this potential.

The operating procedures for fire zone alarm annunciation provide adequate guidance concerning the required actions for a fire in Zone 80 for Unit 1. The guidance for Unit 2 is not as explicit; however, it is considered to be adequate when combined with the abnormal and emergency operating procedures. The licensee is processing charges to the Unit 2 fire alarm procedures to include the detailed guidance of the Unit 1 procedures.

2.1.3 Personnel Practices in the Operations Department

The inspection team identified several concerns and observations with respect to the Operations Department's personnel practices. Although this area was not originally included in the scope of the inspection, it was raised by operators during other inspection activities.

2.1.3.1 Overtime and Shift Staffing Policies

The inspection team reviewed the amount of overtime worked by Operations Department non-supervisory personnel, that is, reactor operators, radwaste operators, and plant equipment operators (PEOs). The review of the overtime practices indicated that excessive overtime, greater than the guidelines provided in TS 6.2.2.e, "Plant Staffing," was authorized almost exclusively to support refueling activities. The inspection team also noted that the unit superintendent whose primary responsibility was scheduling manpower for the unit outages was also responsible for authorizing the excessive overtime. These concurrent responsibilities had the potential to be in conflict. In addition, although the individual excess overtime authorization forms are routed to the operations manager and general manager (who initialed the forms), the forms did not provide information concerning the recent work history of the individual. Thus, the context in which the excessive overtime was authorized was not readily available for the reviewers. In addition, the authorization forms were signed frequently after the excess overtime was worked.

The inspection team reviewed the use of overtime which did not exceed the guidelines of TS 6.2.2.e, but was in excess of the objective stated in TS 6.2.2.e (i.e., greater than a nominal 40-hour week while the plant was operating with a 12-hour shift schedule.) During the period April 21 through July 27, 1990, employees were allowed to work up to 40 percent above their normal schedule.

The inspection team also noted that the operating shifts were not well balanced with regard to the experience levels of non-supervisory personnel such as reactor operators and PEOs. People working on night shifts (shifts D and E) typically had less experience than people working day shifts. In response to this concern, the licensee indicated that the primary contributor to this situation was the seniority system which allowed senior individuals (typically more experienced personnel) the choice of the more desirable day shift positions. In addition, the Operations Department policy of rotating supervisory personnel (i.e., senior reactor operators) every 24 weeks partially compensated for the unequal distribution of experience. This rotation involved senior reactor operators (SROs) who have been assigned to shifts as well as those assigned to administrative duties. The inspection team did not find evidence that the grouping of less-experienced reactor operators and PEOs had resulted in any disproportionate number of events or problems. However, since most of the surveillance activities and calibrations are performed during the night shift, this staffing pattern has the potential to become a weakness.

The inspection team concluded that the potential conflict of interest, the lack of recent work history information, and frequent "after the fact" authorization of excess overtime were weaknesses in the Operations Department's policies for overtime approval. In addition, the non-supervisory staffing policy had the potential to result in unbalanced experience levels on the night shifts.

2.1.3.2 Training of Plant Equipment Operators

During the inspection team's discussions with six plant equipment operators (PEOs), three PEOs indicated that they had been qualified for the auxiliary building without the evaluator having observed their performance of rounds. Two of the PEOs indicated that they had never accompanied another qualified PEO on auxiliary building rounds before being qualified. One of these two indicated that he had already been assigned the position without having been with another qualified PEO during rounds in the auxiliary building.

The Training Department reviewed the circumstances surrounding this qualifications process as described by the specific PEOs. The training manager indicated that the training evaluator responsible for certifying the PEOs had delegated his responsibility for evaluating performance of PEO rounds to a qualified PEO, an individual not designated to be an evaluator. Instead of accompanying the trainees on the rounds, the PEO instructed some of the trainees to make the rounds and return the completed rounds sheets to him. After reviewing these sheets, the PEO initialled them, indicating that the rounds had been properly performed. The evaluator, without speaking with the qualified PEO, observed the PEO's initials and assumed that the PEO had observed the trainees perform the rounds. The evaluator then certified that this task had been satisfactorily demonstrated.

The training manager and Operations Department's training coordinator both indicated that to their knowledge neither Training nor Operations Departments have reviewed the implementation of on-the-job training (OJT) for PEOs. The inspection team was shown that a management observation report (MORE-TQ-3) had been recently issued, but not yet implemented to evaluate OJT in all departments. The lack of OJT evaluations had been identified by the Training Department.

The PEO training program was summarized by the licensee. The training was divided into four major sections: basic, turbine building, auxiliary building, and outside areas. Each part involved 10 to 12 weeks of instruction. The basic training consisted of classroom training in skills and knowledge for such items as tagouts, lineups, and was supplemented with in-plant training by an instructor. The three duty station training sections involved: 8 weeks of classroom instruction with half of the time spent in the plant with the instructor or qualified PEO; 2 weeks of in-plant evaluation in which the trainee was assigned to a shift and was evaluated on specified tasks by either a qualified PEO or an instructor; observation of at least one turnover and performance of PEO duties on one full shift while being evaluated by a qualified PEO; and OJT on performing rounds. Once these items were completed, the PEO was considered fully qualified on the area and assigned a shift. At the discretion of the shift superintendent (SS), a newly qualified PEO could be assigned to a more senior PEO for additional OJT.

The operations manager indicated that he thought a "break-in period" for PEOs would be a good idea and he said would discuss that possibility with the unit shift supervisor responsible for training. The desirability of this was underscored when all of seven PEOs interviewed indicated that either additional time under instruction was desirable or that they had already recommended to management that they receive more instruction.

As discussed in Section 2.2.6 of this inspection report, the inspection team identified inconsistencies in how the PEOs performed rounds. As a followup to this concern, the inspection team asked to see the PEO training records associated with a recent PEO class. As a result of this request, the licensee discovered that when 10 PEOs had completed their qualifications on June 15, 1990, the training qualification checklist had not been signed by the operations manager. The licensee obtained the proper signatures on August 8, 1990.

A review of the qualification sign-off criteria sheets for 1 of 10 PEOs indicated numerous examples of the same omission in properly completing the sheets. In each example, Section III, "Practical Requirements," failed to indicate whether the requirement was completed by either performance (p), simulation (s), observation (o), or discussion (d). The following qualification sign-off criteria sheets had the omission: 1, 9, 10, 12, 13, 15, 16, 20, 22, 24, 27, 29, 44, 45, and 51. These deficiencies were discussed with the operations manager.

The inspection team concluded that the licensee's method of certifying the qualifications for plant equipment operators was not correctly performed. The PEO evaluator, without discussions with the qualified PEO, observed the PEO's initials and assumed that the PEO had observed performance of the rounds. The evaluator then certified that this task had been satisfactorily demonstrated. In addition, the licensee had not conducted a management review of the implementation of the PEO's OJT training. This is an identified weakness within the licensee's operational practices.

2.1.3.3 Quality Concern Program

The licensee's Quality Concern Program was designed to encourage employees to identify items of concern that could potentially affect quality, and to bring these items to the attention of plant management. The program was implemented by the Quality Concerns Coordinator in accordance with Administrative Procedure 00015-C, "Quality Concern Program."

The inspection team reviewed the list of quality concerns to determine if the items were being categorized appropriately (i.e., quality related or non-quality related). The team also reviewed selected concerns to determine the status of the resolution. With respect to this review, the team observed that the method used to identify quality concerns during employment exit interviews did not include a personal interview with each employee because the Quality Concerns Coordinator was not always available. Because the Quality Concerns Coordinator was the only person assigned to the Quality Concerns Program, there were several examples of the exiting employee not having the opportunity to personally identify quality concerns. In addition, the method of assigning the quality concern to the affected department could result in a lack of an independent review.

The inspection team concluded that the Quality Concerns Program had a potential weakness with respect to the method of conducting exit interviews and the assignment of the investigations.

2.2 <u>Control Room Observations</u>

The inspection team observed control room activities on a 24-hour basis for 8 days. During this period, an NRC inspector accompanied the licensed and non-licensed operators on their rounds and observed activities in the control room to verify that facility operations were being safely conducted within regulatory requirements. The team also interviewed licensee personnel, independently performed verifications of safety systems status and LCOs, attended licensee meetings, and reviewed facility records. During these inspections, the team observed the conditions under which materials and components were stored and the cleanliness conditions in various areas in order to determine if safety or fire hazards existed.

The following attributes were verified, as appropriate.

- Control room staffing

- Control room access and operator demeanor
- Adherence to approved procedures for activities in progress
- Adherence to TS limiting conditions for operations
- Observance of instruments and recorder traces of safety-related and important to safety systems for abnormalities
- Review of annunciators alarmed and action in progress to correct
- Control room panel walkdowns
- Safety parameter display and the plant safety monitoring system operability status
- Plant status, licensee plans, and operator knowledge
- Reactor operator logs, unit shift supervisor logs, and shift turnover sheets.

2.2.1 Plant Evolutions and Surveillance Testing

The team monitored control room activities to determine if the operators were attentive and responsive to plant parameters and conditions. In addition, the inspection team observed surveillance tests to verify that approved procedures were being used; qualified personnel were conducting the tests; tests were adequate to verify equipment operability; calibrated equipment was utilized; and TS requirements were satisfied. As a result of this effort, the inspection team identified several concerns which are discussed in Sections 2.2.1.1 through 2.2.1.3.

2.2.1.1 Containment Isolation Valve Operability

On August 6, 1990, during its initial tour of the facility, the inspection team noted that the Unit 2 containment isolation valves (CIVs) associated with Train A of the Hydrogen Analyzer System were open. The open valves were 2HV-2792A, 2HV-2792B, 2HV-2791B and 2HV-2793B. These remotely-operated, manual valves were designated as containment isolation valves in the Final Safety Analysis Report (FSAR) and are not normally open during power operations. Upon questioning, the unit shift supervisor (USS) told the team that the CIVs were opened to allow the performance of Surveillance Procedure 24551-2, "Containment Hydrogen Monitor Analog Operability Test and Channel Calibration." Additionally, the USS indicated that these valves received a containment isolation signal. The operations manager confirmed this statement in a later discussion with the inspection team. The inspection team determined that the CIVs were remotely-operated, manual valves which did not receive an automatic containment isolation signal.

On August 7, 1990, at 2053 hours, the licensee opened the CIVs and initiated similar testing on Unit 1 even though the inspection team had expressed a concern to the operations manager earlier in the day that opening the CIVs violated the LCO of TS 3.6.3. After discussion between the inspection team and the Unit 1 shift superintendent (SS), the SS instructed the reactor operator to close the CIVs and to terminate the surveillance test.

TS 3.6.3, "Containment Isolation Valves," requires when in Modes 1 through 4 that with one or more of the CIVs inoperable,

> Maintain at least one isolation valve operable in each affected penetration that is open and (1) restore the inoperable valve to the operable status within 4 hours, or (2) isolate each affected penetration with 4 hours by the use of one deactivated automatic valve secured in the isolated condition, or (3) isolate each affected penetration within 4 hours by the use of a closed manual valve or blind flange, or (4) be in hot standby within the next 6 hours.

The licensee did not believe that TS 3.6.3, "Containment Isolation Valves," required these CIVs to be closed because an open manual isolation valve was not considered inoperable and the hydrogen monitoring system had been designed to withstand accident containment pressures. However, the inspection team noted that an interpretation for TS 3.6.3 which was approved and issued by the operations manager on January 18, 1990, specifically defined these valves as containment isolation valves and defined an open manual isolation valve as inoperable. In addition, Section 4.2 of Operations Procedure 13130-2, "Post-Accident Hydrogen Control System," Revision 2, cautions that the hydrogen monitoring system isolation valves must remain closed except during hydrogen monitor operation to ensure containment integrity is maintained. Also, FSAR Table 6.2.4.1 listed these valves as containment isolation valves and indicated in Paragraph 6.2.4.2.3 that lines not in use during power operation are normally closed under administrative controls during reactor operations.

The inspection team was also told that the hydrogen monitoring system was considered to be an extension of the primary containment boundary. However, when questioned as to when it was tested as part of the integrated leak rate test (ILRT), the licensee was not sure. The inspection team asked for copies of the system design and test information to determine if the system was designed and tested to a value greater than or equal to the containment design pressure and whether it was tested as part of the ILRT. This information indicated that the hydrogen analyzer system was not tested as part of the ILRT. However, the Unit 2 hydrogen analyzer system was tested by Maintenance Work Order (MWO) 28817590 to 90 pounds per square inch gauge (psig) in accordance with the vendor's instruction. In addition, the instrument tubing between the CIVs was designed to 80 psig. Although this information indicates that the system was designed and initially tested to a pressure higher than containment design pressure, it does not confirm that this equipment will be periodically tested as part of the primary containment boundary.

Additionally, the inspector reviewed the local leak rate procedure (Surveillance Procedure 24932-2) for testing the Unit 2 hydrogen analyzer system CIVs (valves 2HV-2792A, 2HV-2892B, and 2HV-2791B.) Step 3.2 of this procedure stated that "If test is performed in Modes 1 through 4, obtain shift supervisor permission to open valves 2HV-2792A, 2HV-2792B and 2HV-2791B. Opening valves requires entry into an LCO." The review of local leak rate procedures (Surveillance Procedures 24910-2, 24930-2, 24931-2, 24932-2, and 24933-3) indicated that the test was required to be completed within 24-month intervals and should result in testing the piping in question to 45 psig. The inspector was provided copies of completed tests performed in 1988 and 1989 (i.e., within the last 24 months)

A subsequent review of Surveillance Procedure 24551-2, which was one of the four surveillance procedures required for testing the hydrogen analyzers for both units, revealed the following:

1) The procedure's review cover sheet indicated that the Operations Department was not involved in the review and approval process.

2) The procedure's safety evaluation was inadequate, in that the safety evaluation did not explain why the procedure did not involve a change to the Technical Specifications.

3) The procedure was technically inadequate in that it instructed operations of the CIVs and did not caution or specify administrative controls over valve operation. This resulted in violation of TS 3.6.3 requirements. Also, the procedure allowed the test to be conducted in any mode of reactor operation when containment integrity is required.

After discussing its observations with NRR staff, the inspection team concluded that, from a technical position, opening the CIVs did not pose a high risk as long as the equipment was capable of withstanding full containment design pressure. Under these conditions, strict administrative controls for compensatory measures would be acceptable for ensuring that a failure of the equipment would be rapidly detected and would result in timely isolation of the penetration in question. However, opening the CIVs at power should be controlled by the action requirements of the LCO for TS 3.6.3. The team discussed this information with the

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licensee, and asked the licensee to reevaluate the need to open the normally closed CIVs for the purpose of calibrating the hydrogen monitor.

The inspection team concluded that the failure to comply with the action requirements of TS 3.6.3 during the time the CIVs were open was a violation. With inoperable CIVs, TS 3.6.3 required that operability be restored within 4 hours or the units be placed in hot standby within the next 6 hours and in cold shutdown within the following 30 hours. The CIVs were opened on Unit 2 on August 6, 1990, at 0411 hours, and were not closed until August 7, 1990, at 0122 hours; therefore, the Unit 2 CIVs remained open in violation of TS 3.6.3 for a period of 21 hours and 11 minutes. On Unit 1, the CIVs were open for a duration of 18 hours and 47 minutes before they were closed in response to the inspection team's concern. Both units were operating in Mode 1 during the entire period when the CIVs were open. The inspection team also concluded that this violation resulted due to the failure of the Operations Department to adequately review Surveillance Procedure 24551-2, "Containment Hydrogen Monitor Analog Operability Test and Channel Calibration." This item will be followed as violation:

> VIO 50-424/90-19-02; 50-425/90-19-02, "Inadequate Surveillance Procedure Results in a Failure To Maintain Containment Isolation as Required by TS 3.6.3."

2.2.1.2 LCO Action Times

On August 10, 1990, emergency diesel generator (EDG) #1B was taken out of service at 1354 hours for a weekly surveillance. The proper LCO entry time was recorded. However, the inspection team noted that the unit shift supervisor (USS) considered the EDG to be operable and exited the LCO after the local/remote switch was returned to the remote position and before the independent verification steps of the surveillance procedure were completed. Although the EDG was available to start automatically, the USS based his LCO exit on visual confirmation that the remote control of the EDG had been restored and not on the actual performance of the steps of the surveillance procedure. The inspection team also noted that the EDG was considered operable at 1420 hours by the USS; however, the reactor operator did not record it as operable until 1430 hours when the auxiliary building operator reported that the EDG cylinder 1 moisture checks were completed.

The licensee indicated that this was not the usual method of exiting LCOs and that all the surveillance procedure steps and verifications were required to be completed before exiting the LCO action statement. As followup to this concern, the inspection team observed that, during EDG testing on August 7, 1990, the Unit 2 USS properly entered and exited the LCO following an EDG surveillance test. The inspection team had no further concerns in this area.

2.2.1.3 Completed Surveillance Test Procedures

The inspection team verified that the shift superintendent's (SS's) office contained some completed copies of past surveillance procedures. Discussions with the operators indicated that they used the procedures differently. One shift superintendent stated that the procedures were used to verify completion of previous surveillances, especially during mode changes. This was reemphasized by a unit shift supervisor. However, three different unit shift supervisors stated the procedures were to be used for information only. The licensee indicated that the records were actually intended to be used to (1) determine when the surveillance was last run, (2) trend any changing conditions, and (3) compare any confusing steps to previous surveillances.

The inspection team erified that these completed surveillance procedures were not controlled and that several completed surveillances were missing in numerous packages. The Operations Department did not have any administrative controls for these procedures. The inspection team concluded that additional attention is necessary to ensure that these procedures are appropriately controlled and used.

2.2.2 Operator Attentiveness and Response to Plant Conditions

Operators were observed to be prompt in acknowledging all annunciators and changes in plant conditions. Alarm response procedures (ARPs) were used when uncommon alarms were annunciated. Operators were prompt to dispatch the plant equipment operators (PEOs) to respond to local conditions when an alarm was received in the control room. Observation of responses to specific annunciators included: (1) "Generator Excitation Cubicle Alarm" which required sending a PEO to the Unit 1 turbine/generator excitation cabinet, and (2) "Hydrogen Stator Cooling System Trouble," which required that the turbine building PEO be dispatched to the local alarm panel for the cooling system. Each response was proper and in accordance with the ARP.

On August 7, 1990, Unit 2 Operations Department personnel determined that steam generator (SG) No. 4 narrow range level transmitter (LT-554) was indicating erratically. The instrument channel was declared inoperable and the associated bistables were tripped. The inspection team observed that, before tripping the bistables, the reactor operator (RO) asked the senior reactor operator (SRO) to verify that the proper bistables had been identified. One SRO declined to verify this since he had not tripped bistables in several years. Another SRO verified that the identified bistables were the proper ones prior to tripping the bistables. These actions were considered conservative in that similar bistables associated with SG No. 3 were tripped due to a failure of LT-553. If another channel associated with SG No. 3 had inadvertently tripped, the unit would have experienced an indicated low-low SG level trip or a feedwater isolation.

The inspection team also reviewed TM 1-90-023 for the repair of a SG level transmitter (1LT-503) and the coordinated effort to remove the Unit 1 component cooling water (CCW) Pump 1 for repair. Both of these examples indicated that the Operations Department and other departments worked well together to accomplish the necessary task.

Shift superintendents and support shift supervisors frequently conducted plant tours. However, the unit shift supervisors seldom toured the plant. Although required by the Operations Department administrative procedures, plant tours by USSs did not always appear to be feasible or practical because of work demands in the control room. Additionally, discussions with operators indicated that plant managers almost never conducted backshift plant tours.

The inspection team accompanied PEOs on several building tours during routine rounds. Generally, each PEO was knowledgeable and conducted a detailed tour; however, specific concerns regarding one tour are discussed in Section 2.2.6 of this inspection report. The inspection team also noted that the plant equipment status was noted in the control room logs and, when appropriate, LCO logbook entries reflected the status of TS-related equipment.

The inspection team observed activities in the shift superintendent's (SS's) office and noted two minor examples of administrative errors. These were:

1) Two limiting condition for operation (LCO) forms were numbered 1-90-564. However, each was applicable to different sections of the TS. One of the LCOs dealt with turbine-driven auxiliary feedwater system and the other LCO dealt with shutdown rod 15.

2) The operating crew entered an information LCO when boric acid storage tank pressure indicator PI-10115 failed its surveillance. The LCO number listed on the form was 2-90-180. This number did not agree with the number in the LCO log, nor was the subject matter for LCO 2-90-180 the same. The actual LCO number from the LCO log was 2-90-221-I. The shift supervisor corrected the LCO to reflect the correct tracking number.

Through discussions and observations, the inspection team concluded that control room personnel were aware of plant conditions, monitored appropriate parameters, and responded to plant conditions in a satisfactory manner.

2.2.3 Operations Procedural Compliance

The inspection team performed numerous observations of on-shift licensed and non-licensed personnel during procedural implementation. The team observed that personnel adhered to procedures during implementation. Alarm response procedures were followed explicitly. The team observed the performance of the following surveillance procedures:

- 14000-2, Operations Shift and Daily Logs
- 14030-1, Power Range Calorimetric Channel Calibration
- 1422[illegible]-1, Main Turbine Valves Weekly Stroke Test
- 14410-1, Control Rod Operability Test
- 14445-2, Remote Shutdown Monitoring Instrumentation Channel Check
- 14546-1, TDAFW Pump Operability Test
- 14600-1, ESFAS Slave Relay and Final Device Train A Block Test
- 14616-2, SSPS Slave Relay K609 Train A Test Safety Injection
- 14618-1, SSPS Slave Relay K610 Train A Test Safety Injection
- 14618-2, SSPS Slave Relay Train A Test Safety Injection
- 14622-2, SSPS Slave Relay K615 Train A Test Safety Injection
- 14803-1, CCW Pumps and Discharge Check Valves Inservice Inspection
- 14905-1, RCS Leakage Calculation
- 14905-2, RCS Leakage Calculation
- 14915-1, Special Condition Surveillance
- 14915-2, Special Condition Surveillance
- 14980-2, Diesel Generator Operability Test
- 24670-1, Waste Liquid Effluent Process Monitor 1RE-0018 ACOT and Channel Calibration
- 24670-2, Waste Liquid Effluent Process Monitor 2RE-0018 ACOT and Channel Calibration

The inspection team did not identify any deficiencies or concerns with respect to the performance of these procedures.

2.2.4 Shift Communications

Communications within the Operations Department and between operations personnel and other groups were generally adequate. However, on some occasions communications could have been more effective. On August 8, 1990, a high-radiation alarm was received on the SG No. 4 steam line. Apparently, during shift turnover, control room personnel had been told that a source check was to be performed during the shift; however, several hours into the shift, the technician failed to notify the control room before beginning the test. On another occasion, a Unit 2 unit shift supervisor repeatedly acknowledged the receipt of information directed to him by just looking up at the informant. During the performance of a surveillance test, the reactor operator had to repeat the information before the USS acknowledged verbally that he had received the information. In one instance, when the reactor operator repeated that he was about to trip a bistable, the USS appeared irritated, but did respond by stating that he understood that a bistable was about to be tripped. Though communications could be improved, the inspection team concluded that communications had been adequate during this activity.

The inspection team observed that the control room and PEOs maintained continuous communications via headsets during valve manipulations for removing the heater drain tank 1B high-level dump valve from service for maintenance. This activity required close coordination between the control room and PEOs at two different locations in the turbine building. The team concluded that the activity was properly coordinated and appropriate communications were defined and properly executed.

The inspection team routinely attended shift briefings and observed shift turnovers during the inspection period. On August 10, 1990, during the 0700-hour shift briefing, the team observed that some personnel were standing in the hall. Although these people could not hear what was being said, they signed the attendance sheet. After the team identified this concern to the shift superintendent, the situation improved.

The shift turnover meetings tended to be concise and informative. The discussion involved plant and equipment status as well as descriptions of planned major evolutions and work activities. The shift turnover meetings of reactor operators, unit shift supervisors and shift superintendents gave these employees sufficient information on plant status before the oncoming shift assumed its duties. These turnovers involved control board walkdowns, review of appropriate logs, and discussions.

The inspection team also attended the 0715-hour supervisor meetings. At these meetings, supervisors discussed such work activities as maintenance and testing. The inspection team determined that the meeting adequately informed the various group supervisors of required support for scheduled and emergent activities.

The inspection team was informed by the shift superintendent, and later confirmed by the operations manager, that the shift briefings are viewed as being mini-safety meetings. Section 4.5.1 of Operations Procedure 00250-C, "Safety Committee and General Safety Meetings," stated that mini-safety meetings will be held by each department, section, team, discipline, and so forth, on a bi-weekly basis. However, three PEOs assigned to the Operations Department for at least two years indicated that no safety meetings have been held. The only items they could remember being addressed concerning personnel safety were infrequent statements such as, "Be careful out there," and, "Wear your hard hats."

The inspection team concluded that the Operations Department was not properly fulfilling the administrative requirement for performing periodic mini-safety meetings and that this was an operational weakness.

2.2.5 Corrective Actions for Deficiencies and Equipment Failures

The inspection team observed on-shift crew actions during equipment malfunctions and failures. The team noted that the shift crew took prompt actions to identify equipment problems to the appropriate departments for corrective actions. The operating crews monitored operating conditions associated with the malfunctioned equipment and used backup instrumentation, measurements, and readings, as necessary, to verify plant parameters and conditions. The team observed the on-shift crew during times when components had failed or were not functioning properly. For those instances, the USS or SS made the determination whether the component was operable. The team did not observe any instances of the on-shift crew making an improper operability determination. No deficiencies were noted.
The inspection team noted that there have been several recent instances of SG narrow range level instrument failures. Work request tickets (WRTs) were written to correct the problems; however, the root cause of the failures does not appear to have been identified as evidenced by the continuing problems. Further action is needed by the licensee to identify and correct the root cause of the failures.

2.2.6 Performance of Plant Equipment Operators

The inspection team accompanied plant equipment operators (PEOs) during portions of their routine rounds. In each instance, the team determined that the PEOs were knowledgeable about plant systems, knew the location of major components, and conscientiously performed their duties. In some instances, the team determined that the PEO performed a detailed tour. However, in other instances, inconsistencies were evident in the level of detail to which the general area inspections were performed. Instructions on performing a general inspection while performing rounds were contained in Section 3.3 of Operations Procedure 10001-C, "Logkeeping." This section references Table 1 of the procedure for inspection criteria when performing rounds and identifies it as the minimum criteria to which an operator must inspect his assigned area. Table 1 of Operations Procedure 10001-C is a 3-1/2-page list of items which includes such instructions as:

- Pipe hangers intact
- Insulation installed

- Noise and vibration levels normal
- Hose stations properly equipped
- Radiation areas clearly identified
- Hold tags attached
- Temporary modifications clearly marked
- Equipment locked with breakaway locks closed/locked as required
- Operator aids properly approved
- Electrical enclosure covers installed with all fasteners engaged
- Bearing temperature, vibration, and noise normal
- Suction, discharge, and recirculation flow path available
- Ground straps connected

Inconsistencies observed by the inspection team included such items as:

1) One PEO reset every thermal overload on each breaker.
2) One PEO failed to check any hose stations for proper equipment.
3) One PEO failed to identify missing instrument tubing supports and bent tubing during their tours.
4) Not all operating rotating equipment was touched to sense temperatures and vibration.

Discussions with a USS, SS, and the operations manager indicated that Table 1 is meant to be guidance. However, this appears to be in conflict with Section 3.3 of 10001-C which seems to impose minimum criteria. The inspection team was concerned that the actual expectations involving minimum acceptable performance of general inspections were not well defined in procedures nor, in some instances, by on-the-job training (OJT) as described in Section 2.1.3.2 of this inspection report. This was identified as a potential weakness in the licensee's program.

2.2.7 Material Conditions

The team inspected various plant buildings and accompanied licensed and non-licensed shift personnel on their rounds in order to assess the overall status of the plant and equipment. During these tours, the team made several observations concerning the status and condition of equipment. Observations included the following:

1) Excessive amounts of oil on and around EDG #2A.

2) Standing water on the floor in the Unit 2 turbine-driven auxiliary feedwater pump room due to excessive leakage past the pump seals. Although a WRT was written to identify the problem in November 1989, the problem has not been corrected. A second WRT was written in June 1990, which stated that the leakage had gotten worse.

3) There appeared to be a distinct separation in responsibilities for equipment that belonged to the Operations Department and equipment that was the responsibility of other departments or groups (e.g., Chemistry, Radwaste, and Instrumentation). PEOs indicated that they would monitor equipment belonging to another department, but the maintenance and operation were the responsibility of the other departments and not the Operations Department. This was raised when the team asked the PEO to explain why missing instrument tubing supports and bent tubing were not identified by PEOs during their tours.

4) Labels inside breaker panels only have breaker numbers marked; end devices (equipment energized by the breakers) are not designated. To help operators, the Operations Department had to add a cross-reference between the breaker number and the end device on the inside of the panel doors. In general, the non-safety-related panels did not have any designations.

5) On Units 1 and 2, there were several instances of pressure boundary leaks at valve bonnet flanges with a buildup of boric acid precipitate. This boric acid buildup had resulted in surface corrosion.

Despite these deficiencies, the inspection team concluded that the material condition of the facility was acceptable.

2.2.8 Event Classification and Notifications

On August 8, 1990, at 0738 hours, the control room received a Notification of an Unusual Event (NOUE) from the Savannah River site (SRS) involving a Phase I security condition. The emergency notification system (ENS) communicator recorded the message as required. The shift superintendent (SS) promptly notified the VEGP on-call duty manager. The SS informed the inspection team that if a potential radiological release condition had existed at the SRS, he would have made a courtesy "red phone" report to the NRC. At 2002 hours, a second message was received from SRS which stated that the NOUE had been cancelled. The SS notified off-site management of the cancellation.

On August 10, 1990, at 0310 hours, a security officer who was assigned patrol duty, was found asleep in the central alarm station (CAS). Upon notification, the SS and Unit 1 Unit shift supervisor referred to the notification procedure to determine reportability. The on-duty manager was notified. There was discussion that this may not be reportable because of the specific circumstances. The SS was informed that management would get back to him. At 0407 hours, the SS had not been contacted by management. Since the SS believed that the event met the criterion of a 1-hour "red phone" report, he notified the NRC of the event.

On another occasion, the inspection team observed that the SS had notified the NRC duty officer upon discovery of a confirmed positive drug test of a non-licensed supervisor. The report was made as required by the VEGP fitness for duty program.

The inspection team concluded that the licensed operators had appropriately classified the events and performed the proper notifications.

3.0 EXIT INTERVIEWS

The inspection scope and findings were summarized on August 17, 1990, with those persons indicated in Appendix 1. The inspection team described the areas inspected and discussed in detail the inspection results. The licensee made numerous dissenting comments. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspector during this inspection.

APPENDIX 1

PERSONS CONTACTED

Licensee Employees

*J. Aufdenkampe, Manager Technical Support
*G. Bockhold, Jr., General Manager Nuclear Plant
*D. Carter, Shift Superintendent
J. Bowden, Work Planning
J. Cash, Unit Superintendent
M. Chance, Senior Engineer, Engineering Support
*S. Chesnut, GPC Technical Support
C. Coursey, Maintenance Superintendent
W. Diehl, Shift Supervisor, Operations
*G. Frederick, Safety Audit and Engineering Group Supervisor
J. Gasser, Shift Superintendent, Operations
*L. Glenn, Manager - Corporate Concerns
*D. Gustafson, Maintenance Engineering Supervisor
J. Gwin, Corporate System Engineer
*H. Handfinger, Manager Maintenance
*K. Holmes, Manager Training and Emergency Preparedness
*M. Horton, Manager Engineering Support
B. Kaplan, Senior Engineer, Engineering Support
G. Lee, Plant Engineering Supervisor, Operations
*R. LeGrand, Manager Health Physics and Chemistry
W. Lyons, Quality Concerns Coordinator
*G. McCarley, Independent Safety Engineering Group Supervisor
*C. McCoy, Vice-President, GPC
*R. McDonald, Executive Vice-President, GPC
*D. Moncus, Outage and Planning
*A. Mosbaugh, VEGP Staff
R. Odom, Nuclear Safety and Compliance Manager
*A. Rickman, Senior Engineer - Nuclear Safety and Compliance
*L. Russell, Independent Safety Engineering Group - SONOPCO
*M. Sheibani, Senior Engineer
*C. Stinespring, Manager Plant Administration
*S. Swanson, Outage and Planning Supervisor
*J. Swartzwelder, Manager Operations
E. Thorton, Shift Supervisor, Operations
*E. Toupin, Oglethorpe Power Corporation
C. Tynan, PRB Secretary
S. Waldrup, Planning and Scheduling Supervisor
J. Williams, Shift Superintendent, Operations

* Attended exit interview, August 17, 1990.

APPENDIX 1

PERSONS CONTACTED (continued)

NRC Employees Who Attended Exit Interview

R. Aiello, Resident Inspector - Vogtle
B. Bonser, Senior Resident Inspector - Vogtle
M. Branch, Senior Resident Inspector - Watts Bar
K. Brockman, Chief, Reactor Projects Section 3B - RII
R. Carroll, Project Engineer - RII
L. Garner, Senior Resident Inspector - Robinson
N. Hunemuller, Reactor Engineer - NRR
D. Matthews, Project Director - NRR
J. Milhoan, Deputy Regional Administrator - RII
L. Reyes, Director Division of Reactor Projects - RII
R. Starkey, Resident Inspector - Vogtle
P. Taylor, Reactor Inspector - RII
M. Thomas, Reactor Inspector - RII
C. VanDenburgh, Section Chief - NRR
J. Wilcox, Operation Engineer - NRR

APPENDIX 2

LIST OF ACRONYMS

AFD	Axial flux difference
AFW	Auxiliary feedwater
ALARA	As-low-as-reasonably achievable
ARP	Annunciator response procedure
CAS	Central alarm station
CCW	Component cooling water
CFR	Code of Federal Regulations
CIV	Containment isolation valve
DC	Deficiency card
DCP	Design change package
DNB	Departure from nucleate boiling
DRP	Division of Reactor Projects
ECCS	Emergency core cooling system
EDG	Emergency diesel generator
ENS	Emergency notification system
ESF	Engineered safety features
ESFAS	Engineered safety features actuation system
FSAR	Final Safety Analysis Report
GL	Generic letter
GPC	Georgia Power Company
GPM	Gallons per minute
ILRT	Integrated leak rate test
kV	Kilovolt
LCO	Limiting condition for operation
LER	Licensee Event Report
LLRT	Local leak rate test
LOOP	Loss of offsite power
MWO	Maintenance work order
NOUE	Notification of unusual event
NPF	Nuclear power facility
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSCW	Nuclear service cooling water
OI	Office of Investigations
OJT	On-the-job training
PEO	Plant equipment operator
PM	Preventative maintenance
PRB	Plant Review Board
psig	Pounds per square inch gauge
QA	Quality Assurance
RCS	Reactor coolant system
RHR	Residual heat removal
RII	Region II Office
RO	Reactor operator
SG	Steam generator
SONOPCO	Southern Nuclear Operating Company
SRO	Senior reactor operator

APPENDIX 2

LIST OF ACRONYMS (continued)

SRS	Savannah River site
SS	Shift superintendent
SSPS	Safety System Parameter System
TDAFW	Turbine-driven auxiliary feedwater
TM	Temporary Modification
TS	Technical Specification
URI	Unresolved item
USS	Unit shift superintendent
VEGP	Vogtle Electric Generating Plant
VIO	Violation
WRT	Work request ticket

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

DEC 1 0 1990

Docket Nos. 50-424, 50-425
License Nos. NPF-68, NPF-81

Georgia Power Company
ATTN: Mr. W. G. Hairston, III
Senior Vice President -
Nuclear Operations
P. O. Box 1295
Birmingham, AL 35201

Gentlemen:

SUBJECT: SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE
(NRC INSPECTION REPORT NOS. 50-424/90-23 AND 50-425/90-23)

The NRC Systematic Assessment of Licensee Performance (SALP) has been completed for your Vogtle facility. The facility was evaluated for the period of October 1, 1989 through September 30, 1990. The results of the evaluation are documented in the enclosed Initial SALP Report. This report will be discussed with you at a public meeting to be held at the Vogtle facility in Waynesboro, Georgia, on December 18, 1990, at 10:00 a.m.

The performance of your Vogtle facility was evaluated in the functional areas of Plant Operations, Radiological Controls, Maintenance/Surveillance, Emergency Preparedness, Security, Engineering/Technical Support, and Safety Assurance/Quality Verification. Overall, the assessment indicates that the Vogtle facility was operated in a safe manner. Radiological Controls practices were noted as being superior. However, demonstrated performance deficiencies in the Security and Emergency Preparedness areas indicate a need for continued aggressive and extensive management attention.

The loss of vital ac power event on March 20, 1990, and the resultant declaration of a Site Area Emergency was the dominant operational occurrence during this rating period. While the immediate response of site personnel was effective in precluding the endangerment of the public, performance deficiencies were identified. You have initiated an extensive corrective action program to correct the shortcomings and preclude their recurrence. It is essential that this program be continued and that the lessons learned be integrated into your daily operational activities.

A special NRC team inspection was performed in August 1990, to determine whether the facility was being operated in a safe manner. Based upon this inspection it was determined that Vogtle was being operated in a safe manner, but there were operational practices where weaknesses were identified. The results of this special team inspection will be transmitted under separate correspondence.

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The great diversity of categorical ratings within this report indicate that firm management is needed to ensure uniform, consistent guidance for operating the facility. NRC inspection efforts over the next SALP period will focus on evaluating whether this consistency is developed.

Any comment you have concerning our evaluation of the performance of your Vogtle facility should be submitted to this office within 30 days following the date of our meeting. These comments will be considered in the development of the Final SALP Report. Your comments and a summary of our meeting will be issued as an appendix to the Final SALP Report.

Should you have any questions concerning this letter, we will be glad to discuss them with you.

Sincerely,

James L. Milhoan for
Stewart D. Ebneter
Regional Administrator

Enclosure:
Initial SALP Report - Vogtle

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(cc w/encl cont'd - see page 3)

DEC 1 0 1990

cc w/encl: (Continued)
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ENCLOSURE

INTERIM SALP BOARD REPORT

U. S. NUCLEAR REGULATORY COMMISSION
REGION II

SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE
INSPECTION REPORT NUMBERS
50-424/90-23 AND 50-425/90-23

GEORGIA POWER COMPANY

VOGTLE, UNITS 1 AND 2

OCTOBER 1, 1989 THROUGH SEPTEMBER 30, 1990

TABLE OF CONTENTS

I. INTRODUCTION

The Systematic Assessment of Licensee Performance (SALP) program is an integrated NRC staff effort to collect available observations and data on a periodic basis and to evaluate licensee performance on the basis of this information. The program is supplemental to normal regulatory processes used to ensure compliance with NRC rules and regulations. It is intended to be sufficiently diagnostic to provide rational basis for allocation of NRC resources and to provide meaningful feedback to the licensee's management regarding the NRC's assessment of their facility's performance in each functional area.

An NRC SALP Board, composed of the staff members listed below, met on November 20, 1990, to review the observations and data on performance, and to assess licensee performance in accordance with the guidance in NRC Manual Chapter NRC-0516, "Systematic Assessment of Licensee Performance". The Board's findings and recommendations were forwarded to the NRC Regional Administrator for approval and issuance.

This report is the NRC's assessment of the licensee's safety performance at the Vogtle Units 1 and 2 for the period October 1, 1989 through September 30, 1990.

The SALP Board for Vogtle was composed of:

L. A. Reyes, Director, Division of Reactor Projects (DRP), Region II (RII) (Chairperson)
A. F. Gibson, Director, Division of Reactor Safety, (DRS), RII
B. S. Mallett, Deputy Director, Division of Radiation Safety and Safeguards, (DRSS), RII
A. R. Herdt, Chief, Reactor Projects Branch 3, DRP, RII
D. B. Matthews, Director, Project Directorate II-3, Office of Nuclear Reactor Regulation (NRR)
D. Hood, Project Manager, Project Directorate II-3, NRR
B. R. Bonser, Senior Resident Inspector, Vogtle, DRP, RII

Attendees at SALP Board Meeting:

K. E. Brockman, Chief, Project Section 3B, DRP, RII
S. E. Sparks, Project Engineer, Project Section 3B, DRP, RII
R. F. Aiello, Resident Inspector, Vogtle, DRP, RII
R. D. Starkey, Resident Inspector, Vogtle, DRP, RII
G. R. Wiseman, Reactor Engineer, Technical Support Staff, DRP, RII

II. SUMMARY OF RESULTS

During this assessment period, Vogtle has been operated in a safe manner. Plant management has maintained an active involvement in directing daily plant operations. Concern has been expressed over the licensee's commitment to fostering effective communications channels, both with the NRC and within its own organization. Also, operational occurrences and inspections have identified the licensee's commitments to conservative operations and implementation of effective risk management as areas requiring continuing attention.

On March 20, 1990, the site experienced a loss of vital ac power which resulted in the loss of all shutdown cooling for a period of 36 minutes. Overall, the response of the plant staff was successful in ensuring the health and safety of the public was maintained. However, numerous shortcomings were identified in areas such as procedural adequacy, command and control, and outage management.

Performance in the area of Radiological Controls continued to be very effective. A reduction in the number of personnel contamination events and a decrease in contaminated area was observed. The program to control and quantify radioactive effluents, as well as the program to reduce the number of out-of-service channels in process and effluent monitors, was considered a strength.

Satisfactory performance was identified in the Maintenance/Surveillance area. Improvements were noted in preventive and predictive maintenance programs. The material condition of the plant is being greatly improved. However, inadequacies were identified in the safety system outage program philosophy. Technical Specification (TS) surveillances also continued to be missed. Maintenance activities contributed to four reactor trips during the assessment period.

The March 20 event identified significant problems in the Emergency Preparedness area, as demonstrated by the site's failure to make timely notifications to emergency agencies, event classification procedure weaknesses, loss of command and control, and personnel accountability problems. Management attention and corrective actions were evident during the subsequent annual exercise.

The licensee continued to experience significant difficulties in the area of control and protection of safeguards information. Some improvement was noted in the security program in the areas of training, armed response capability, and search equipment. However, corrective actions to resolve weaknesses have been slow. Inadequacies were also identified in alarm assessment capabilities and the manner in which contingency drills were conducted.

Engineering/Technical Support effectiveness was inconsistent during the assessment period. Site engineering involvement in daily activities was evident, control over the design change process was demonstrated, and engineering evaluations were typically comprehensive. However, several engineering deficiencies were noted during the assessment period, such as drawing legibility, check valve testing, and recurring Emergency Diesel Generator (EDG) temperature switch problems. Communications between the various technical departments within the plant could be improved. Deficiencies in outage management and risk assessment, identified after the March 20 event, have received increased attention at both the site and corporate levels.

Safety Assessment and Quality Verification were satisfactorily implemented during this assessment period. The Plant Review Board was effective. The Quality Assessment program identified numerous significant issues. Radiological control audits were aggressive in identifying deficiencies. Additional management attention was noted in root cause analysis and corrective actions, however, longstanding problems were not always recognized and corrected.

Overview

Performance ratings assigned for the last rating period and the current period are shown below.

Functional Area	Rating Last Period 10/1/88 - 9/30/89	Rating This Period 10/1/89 - 9/30/90
Plant Operations	2	2
Radiological Controls	2 (Improving)	1
Maintenance/Surveillance	1	2
Emergency Preparedness	2	3 (Improving)
Security and Safeguards	2 (Declining)	3
Engineering/Technical Support	2	2
Safety Assessment/ Quality Verification	2	2

III. CRITERIA

The evaluation criteria which were used to assess each functional area are described in detail in NRC Manual Chapter MC-0516, which can be found in the Public Document Room files. Therefore, these criteria are not repeated here, but will be presented in detail at the public meeting to be held with licensee management. However, the NRC is not limited to these criteria and others may have been used, where appropriate.

IV. PERFORMANCE ANALYSIS

A. Plant Operations

1. Analysis

This functional area addressed the control and performance of activities directly related to operating the facility (including fire protection).

Overall, operational performance during the assessment period was adequate. Licensed and non-licensed operators displayed competence in performing their duties. Normal shift staffing levels exceeded TS requirements. However, past attrition of licensed operators prevented the licensee from attaining their goal of assigning extra personnel to shift coverage. In response, early in this SALP period, the license instituted a cash incentive program to promote licensed operator retention. While attrition during the past year has been low, whether this incentive program has resulted in a long term correction has yet to be determined.

Operators continued to display a professional attitude toward their responsibilities while maintaining a good control room demeanor. They were attentive to annunciators and knowledgeable of changing plant conditions. Turnover checklists were thorough and detailed. Shift crew briefings were adequate and provided necessary plant status for the oncoming crew. During the assessment period, Reactor Operators adopted the use of a twelve-hour shift schedule, resulting in improved continuity, fewer shift turnovers, and better implementation of the team concept. Control room log book entries were legible and accurately reflected plant status. An exception to good log keeping was identified with EDG start failures. Numerous EDG start failures were not considered to be valid and were, therefore, not appropriately logged. Proper logging of the EDG response could have led to an earlier recognition of the EDG air start valve problem discussed in Section IV.G.

The most significant operational event of the assessment period occurred on March 20, 1990, when Unit 1 experienced a loss of all safety (vital) ac power. In response to this event, an Augmented Inspection Team (AIT) was dispatched to the site on March 21, 1990. This inspection effort was subsequently upgraded to an Incident Investigation Team (IIT) which culminated in the issuance of NUREG-1410.

Overall, the plant staff's response to the event was successful in minimizing the threat to public health and safety. Aggressive actions were taken to re-establish shutdown cooling and containment integrity. Both short-term and long-term alternatives were pursued by the plant staff in trying to restore vital electrical power. However, numerous shortcomings were identified during the event. No procedures existed to assist the staff in re-establishing vital ac power from potential sources such as the non-vital buses, or Unit 2. Long-standing deficiencies in the protective trip system for the EDGs were discovered. Application of effective risk management in the licensee's outage management philosophy was brought into question (Section IV.F). The ability of the licensee to accurately reconstruct the details of the event and to communicate these details and other information to the Commission was poor.

During this assessment period, one incident occurred in which operations personnel made decisions and took actions without sufficient support or input from either the applicable onsite or offsite organizations. This incident occurred during the Unit 1 refueling startup when shutdown bank E dropped to zero steps from a withdrawn position. Operations performed trouble-shooting activities and resumed the control bank worth measurements without obtaining any technical input from other plant groups for establishing proper procedural controls.

During the last two SALP periods, problems were identified within the Operations area concerning attention to detail. These problems have continued as exemplified by decisions to make a Mode change while in an LCO Action Statement, and by the removal of both trains of Containment Spray from service during a Mode which required one train to be operable.

Operations management continued to have an active involvement in daily plant operations. Daily operations status meetings were attended by both site and corporate management. This has promoted open discussions between all department managers concerning plant status. A general area of concern throughout this SALP period has been communications between management and the NRC. These communication channels have recently improved as was evidenced by an increase in licensee management interface with the resident inspectors on information regarding potential regulatory issues and maintenance problems. An additional example of management involvement has been the Management Observation Program. This program, which includes mandatory field observations by all levels of plant managers, has provided a formal means for management to evaluate plant activities.

During a Unit 1 walkdown conducted by an NRC inspector, several valves were identified as missing their label tags. This was the result of plant personnel failing to initiate actions to replace the tags in accordance with plant procedures. The licensee is currently conducting a retagging effort to resolve these discrepancies in Unit 1, scheduled to be completed in 1991. Labeling in Unit 2 was observed to be adequate. Based on inspector walkdowns, housekeeping was determined to be satisfactory.

During this assessment period, Unit 1 experienced four unplanned reactor trips. Two were manually actuated and two were automatically actuated. Two of these trips were caused by personnel error when personnel working on or near sensitive equipment initiated actions which subsequently caused the reactor trips. The other two trips were caused by electrical equipment malfunctions which in one case resulted in the loss of control power to both main feedwater pumps and in the other case caused a Main Steam Isolation Valve (MSIV) to fail closed.

Unit 2 experienced seven unplanned reactor trips during this assessment period. Three of the unplanned trips were manually actuated and four were automatically actuated. Four of the seven trips were partially caused by personnel error and included: (1) using improper techniques while valving in 'A' Heater Drain Tank high level dump valve following maintenance, (2) failing to maintain proper steam generator level while awaiting main turbine roll, (3) incorrectly aligning the 'B' heater drain tank high level dump valve during maintenance, and (4) incorrectly setting the tap for the variable ratio current transformers located on the generator main output breakers. The remaining three trips were caused by equipment failures and included: (1) an MSIV closure due to a non-isolable hydraulic fluid leak, (2) a dropped control rod due to failure of a diode on a rod gripper control card, and (3) an MSIV closure due to the failure of a seal-in relay.

The licensee's evaluation of each trip and the resulting corrective actions to prevent recurrence has shown mixed success. The total number of unplanned trips has not significantly decreased from the previous assessment period (ten to eleven), and trips related to personnel error have increased from three to six.

A detailed review of Emergency Operating Procedures (EOP) was conducted by the NRC during this assessment period. The EOPs were adequate to cover the broad range of accidents and equipment failures necessary for the safe shutdown of the plant. Accident mitigation strategies were, generally, in accordance with guidelines. Procedural steps had been appropriately modified to improve human factors, comply with the writer's guide, and incorporate unique plant configurations. The licensee had applied a single writer's guide to EOPs and AOPs resulting in improved procedural consistency. Weaknesses included an inadequate engineering evaluation of an emergency response guideline which had not been included in the EOPs, technical deficiencies and a lack of detail in the EOPs and Abnormal Operating Procedures (AOPs), inadequate step deviation documentation, and weak administrative controls for verification and validation. The licensee is committed to correcting these weaknesses in an expeditious manner.

The licensee's fire protection activities have improved during the assessment period. Fire team members responded quickly and appropriately during observed drills. Additional plant staff participated in the drills to assist the fire team in staging support equipment. A fire drill scenario was developed which permitted the actual charging and discharging of fire hoses. This scenario provided realistic training in fire hose handling techniques which is an improvement over prior practices.

Three violations were cited.

2. Performance Rating

Category: 2

3. Recommendations

The Board had great difficulty in determining the final performance rating for the plant in this functional area.

During the rating period, it was noted that there were numerous instances when activities were pursued without interactive communications having been established between the various cognizant groups at the plant. Attention to detail continued to be a problem and contributed to several operational occurrences. Finally, plant configurations were established which, when combined with operational events, resulted in situations which aggrevated plant responses and allowed the plant's engineering safety features to be challenged.

The Board concluded that the proper characterization of this area was a Category 2; however, inspection effort should remain high and the licensee needs to improve performance throughout those areas which impact plant operational activities.

B. Radiological Controls

1. Analysis

This functional area addressed those activities directly related to radiological controls and primary/secondary chemistry control, reviewed during routine inspections conducted throughout this assessment period.

The licensee's radiation protection staff was well qualified and had the expertise necessary to implement effective programs. Staffing levels, including Health Physics (HP), Radwaste, Chemistry, and Transportation staffs were proper to support routine and outage operations. During the Unit 1 second refueling outage (1R2), the licensee had to authorize several overtime requests to support the outage. To preclude this increased overtime from recurring, the licensee increased the contract HP Technician staff to support the Unit 2 first refueling outage (2R1). In addition, the licensee made better use of the HP staff during 2R1, including use of more roving HP technicians in containment. The training programs for HP technicians and General Employee Training in radiation protection were well defined and effectively implemented.

The licensee's program for maintaining occupational exposures as low as reasonably achievable (ALARA) was effective, mainly due to effective control of source terms. During this assessment period, the licensee's collective radiation dose was approximately 166 Rem. This was an increase from the previous assessment period, but was expected due to two refueling outages in 1990 and an increase in work scope for 1R2. Licensee management continues to establish aggressive collective dose goals and closely monitors performance toward these goals. This performance reflects a strong management commitment to ALARA.

During the assessment period, there was a significant decrease in personnel contamination events (PCEs). The licensee experienced 123 PCEs during the assessment period, which was well within the licensee's goal of 223 PCEs. The decrease was partly attributable to the relatively low number of contaminated work areas.

As indicated above, licensee management was effective in minimizing the contaminated areas [illegible] the plant. During this assessment period, the average area of the plant controlled as contaminated was 3,583 square feet, or less than one percent of the total plant area. This was a decrease from the previous assessment period, in which the licensee maintained an average of [illegible] square feet of the plant controlled as contaminated. [illegible]ease in contaminated square footage resulted from a more aggressive decontamination effort, an increase in the number of decontamination personnel, and the implementation of the catch basin leak containment program.

There is effective coordination and cooperation between the HP group and other organizations. The HP group actively participates in the Plan of the Day meetings.

The licensee's program to control and quantify radioactive effluents was implemented effectively. Liquid and gaseous effluents from July 1989 to June 1990 were within the dose limits specified by TS and within the radioactivity concentrations specified in 10 CFR Part 20, Appendix B. Gaseous releases for the first half of 1990 had decreased slightly as compared to the last half of 1989. The waste gas system had been constructed for essentially zero waste gas decay tank releases and the plant's gaseous releases were typically confined to containment vents and purges. Liquid fission and activation products for the first half of 1990 increased as compared to the last half of 1989. This increase was attributed to 1R2, and to the absence of refueling outages during the last half of 1989.

There were no unplanned or accidental releases during the assessment period, and no TS required liquid or gaseous effluent monitoring instrumentation inoperable for greater than 30 days during this time period. The maximum doses to an individual member of the public due to their activities inside the site boundary during the first half 1990 were consistent with formerly reported doses in the previous semiannual effluent report, and well within regulatory requirements.

As noted in the previous SALP report and again during this assessment period, the licensee's program to reduce the number of out-of-service (OOS) channels in the process and effluent monitors remains effective. The number of OOS channels did not increase over the average 1989 values and TS required monitors received priority attention to prevent extended LCO requirements.

Primary and secondary chemistry parameters were maintained within TS requirements and Electric Power Research Institute (EPRI)/Steam Generator Owners Group (SGOG) guidelines. The facility maintained very low dose equivalent iodine values for both units which indicated good fuel integrity.

The licensee continued to have operability problems with the Post Accident Sampling Systems (PASS) on both units. These operability problems included online monitors, system valves, and sample mixing within the system. Earlier in 1990, the licensee determined the causes and took corrective actions for problems associated with inconsistent automatic dilution of liquid samples and with low hydrogen results as compared to routine reactor coolant analyses. Although progress was made in these specific problem areas, overall system operability was not consistently maintained. This system is very complex and requires extensive technical effort to correct component failures. Consequently, the licensee has agreed to implement a program, with milestone dates, to improve overall PASS reliability.

The licensee's environmental laboratory demonstrated the ability to accurately measure radioactivity in the environment. The laboratory experienced little personnel turnover and the current staff appeared knowledgeable in their various areas. The personnel involved in sample collection were well trained and knowledgeable of sampling procedures and TS requirements for environmental monitoring. Analytical procedures were complete with sufficient detail. Furthermore, the laboratory performed well in the Environmental Protection Agency crosscheck program.

No violations were cited.

2. Performance Rating

Category: 1

3. Recommendations

None

C. Maintenance/Surveillance

1. Analysis

During this assessment period, NRC inspections were conducted in the area of maintenance, surveillance, and refueling activities. The inspections included a review of the administrative controls, the technical adequacy of the procedures, and the implementation of the Maintenance and Surveillance Programs. Activities inspected also included corrective maintenance, preventive maintenance, predictive maintenance, equipment control, equipment status tracking, functional testing, containment tendon surveillance, snubber testing program, and housekeeping.

Staffing of the maintenance department was sufficient to accomplish maintenance activities. Training and qualifications of personnel at all levels was acceptable. Management and supervisory ranks continued to remain stable. Staffing levels were continuously being reviewed to ensure an appropriate mix of craft personnel. Contract craft personnel were replaced as maintenance personnel complete the accredited training program.

The licensee was effective in identifying and correcting programmatic weaknesses in the maintenance area. During the past year, the maintenance engineering group issued a welding manual which replaced several implementing procedures. In November of 1989, the maintenance department revised the Maintenance Work Order (MWO) program. The new program utilizes a Work Request Tag (WRT). Operations submits the WRT to Work Planning which subsequently converts the WRT tag to a MWO which includes the WRT number. With this new system, personnel in the field can now readily identify both the problem and MWO by utilizing the WRT cross reference.

The maintenance department lessons learned program (outage and non-outage) continued to play an active role in promoting a safe and efficient working environment. Information gained was utilized in several areas, such as shift scheduling for supervisors, foreman and craftsman, establishing effective communications at all levels of the department, and routine problem areas. To reduce problems that developed in performing routine tasks, the maintenance department set up a pilot program to perform a self-assessment of the department. Identified problems were resolved and documented. The maintenance department intends to implement this program fully following 2R1. The outage lessons learned program has helped to improve Vogtle's maintenance performed during the outage. Examples of implemented improvements included equipment hatch lifting techniques, containment communications, and establishing a maintenance point-of-contact and a tool shop inside containment.

During the previous assessment period, planned and corrective maintenance backlogs were significantly reduced. Maintenance backlog continued to decrease by approximately 10 percent during this assessment period. Work orders on hold or having a restraint were noted and expedited. Vogtle's safety system outage program had previously been recognized as being effective in minimizing the time components and systems were OOS, in reducing the work scope of refueling outages, in reducing the overall number of clearances, and in reducing the backlog of both corrective and preventive maintenance. However, a shortcoming in the implementation of this program was identified during this assessment period. Phase II of the snubber reduction program resulted in the initiation of safety system outages (e.g., Residual Heat Removal (RHR) and Nuclear Service Cooling Water (NSCW) systems) solely for the purpose of replacing snubbers with struts. Initiating outages for this unique purpose, not integrating maintenance, surveillance, and modification activities, detracted from previous accomplishments of the safety system outage philosophy.

In January 1990, a major coatings upgrade program was implemented. The material condition of plant components and structures is being greatly improved with this program. To accomplish the goals of the program, an integrated schedule through December 1992 has been developed. However, a lack of adequate administrative controls for evaluating and monitoring painting activities within the plant resulted in an inoperable EDG on June 19, 1990. The painter's standard practice of taping stainless steel and moving parts of equipment resulted in the EDG fuel racks being taped in the shutdown position. The painters were not cautioned to be aware of the fuel racks, were not aware that the EDG had to remain available for emergency starts, and did not recognize (on a walkdown) that the operability of the diesel could be affected. In an effort to mitigate any further occurrences of this nature, an interim painting walkdown checklist has been developed to ensure operability concerns are identified and addressed prior to application.

Several changes and improvements have been implemented in the predictive maintenance program in the past year. Miscellaneous equipment not included in the normal predictive scope now receives vibration and lubrication condition monitoring on a routine basis through the use of area predictive tasks. A corporate task force developed an infrared thermography program. Two thermographic surveys at the Vogtle site detected anomalies such as condenser air inleakage, overheating conductors, and overheating of the Unit 1 Isophase Bus Duct.

Programmatic weaknesses in preventive and corrective maintenance continued to be highlighted by both corporate and site management. The preventive maintenance program has been completely revised from the previous cumbersome and regimented approach to a reliability centered program. The effort was to build a preventive maintenance program that would be based on reliability centered maintenance techniques as defined by EPRI and the Institute for Nuclear Power Operations (INPO) but without an expansive use of contractors or a loss of expertise used in establishing the existing program. Effective prioritization has allowed work activities to be accomplished consistent with manpower availability.

A program was initiated this past year to modify valves in the plant to accept live load packing to reduce leakage and improve material condition. During 1R2 a total of 16 valves, primarily in the secondary plant, were modified. Approximately 60 valves will be modified during 2R1. After 2R1, additional valves for live load packing will then be identified.

During the SALP period, the licensee continued the snubber reduction program initiated to reduce maintenance activities and exposure workers received when performing surveillance activities. Phase I, completed during 1R2, involved the removal of 75 snubbers and 19 support modifications in the Main Steam, Containment Spray and the Auxiliary Feedwater systems. Phase II, started during this assessment period, addressed all of the systems with snubbers outside containment. Thus far, 176 snubbers have been removed and 83 supports modified.

During the previous assessment period, isolated instances of missed surveillances were noted. While fewer TS surveillances have been missed during this SALP period, this continues to be a weakness at Vogtle. Five surveillances were noted to be incomplete or inadequately performed prior to the due date and two were not performed at all by their due date. These problems were attributed to misleading task sheets, personnel error, and procedural inadequacy. Once discovered, the licensee promptly performed the surveillances. The licensee is transferring the surveillance tracking program to the site main-frame computer, to improve reliability and to provide all site personnel with access to the information.

The implementation of the Inservice Inspection (ISI) program was reviewed during the assessment period. ISI personnel were cognizant of examination requirements and well qualified. Procedures were sufficiently defined and available to personnel during examinations. Planning of testing activities and tracking of results indicated management involvement in the ISI program. During 1R2, the major Inservice Inspection (ISI) work performed consisted of Eddy Current testing on all steam generators. These exams resulted in the plugging of 4 tubes, 3 of which were discretionary. This reflects a conservative approach to steam generator tube plugging.

During the assessment period, maintenance activities contributed to four unplanned reactor trips: (1) Unit 1 trip when maintenance workers accidently shut off the control air to a MSIV causing the valve to close; (2) A Unit 1 trip when the MSIV control fuses failed after a jumper was installed per procedure; (3) A heater drain tank level control valve reassembly error led to a high level in the moisture separator reheater and Unit 2 trip; (4) A Unit 2 trip after packing replacement of the heater drain tank level control valve. These trips are further discussed in Section V.H. In response, the licensee has incorporated into the Plan Of the Day (POD) an evaluation of the potential trip hazards that should mitigate any further trips of this nature.

Three violations were cited.

2. Performance Rating

Category: 2

3. Recommendations

The Board noted that there has been improvement in numerous areas within the predictive and corrective maintenance programs. However, the Board also noted that the timely and comprehensive completion of surveillances was a continuing problem. Even more significant, maintenance/surveillance activities were direct contributors to four reactor trips during this period. The Board concluded that the appropriate characterization of performance over the entire SALP period was a Category 2.

D. Emergency Preparedness

1. Analysis

This functional area included the evaluation of activities related to the implementation of the Emergency Plan and procedures, the support and training of onsite and offsite emergency response organizations, and the licensee's performance during emergency exercises and actual events. Performance was also evaluated in the areas of and interactions between onsite and offsite emergency response organizations. During the assessment period, inspectors conducted one routine inspection, and one exercise evaluation inspection.

The loss of Unit 1 vital ac power event on March 20, 1990, resulted in a Site Area Emergency (SAE) declaration. Additionally, a Notification of Unusual Event was declared for a TS required shutdown during this SALP period. Two Emergency Plan changes have been submitted and were being reviewed at the end of the SALP period.

The emergency response facilities were maintained in an acceptable state of readiness. One exception to this was that procedures in several facilities were not maintained current. Staffing levels and response facilities were demonstrated to be sufficient during the August 1, 1990 exercise.

During the March 20, 1990 event, notification of Burke County and the Georgia Emergency Management Agency Operations Center was not accomplished until approximately one hour after the SAE was declared. This failure to make the required timely notifications resulted from the loss of the Emergency Notification Network (ENN) in the Control Room, due to the loss of vital ac power, and the fact that the backup ENN was not designed to reach the Georgia emergency agencies. Training and procedural deficiencies also contributed to the delay. This failure to make the required timely notification resulted in a Severity Level II violation and a civil penalty ($40,000).

The classification of the event as an SAE was deemed appropriate, even though the classification procedure was ambiguous and lacked sufficient site specific detail. During the previous assessment period, a loss of command and control was noted during the performance of the emergency exercise. Command and control problems within the site's emergency response organization were again highlighted during the March 20 event. During the event, the operation shift superintendent decided not to include a portion of the site announcement that would have instructed nonessential personnel to leave the protected area. The licensee's site evacuation procedures also did not provide adequate direction in this area, which led to some confusion among site personnel and resulted in an accountability problem.

The licensee's root cause analysis of the March 20, 1990, event resulted in the following extensive corrective actions: (1) The Primary Emergency Notification (ENN) power capability has been changed to include battery backup and personnel have been trained on power supplies; (2) The Backup ENN has been expanded to reach all outside agencies. Communicators have been trained that both Primary and Backup ENNs reach all agencies; (3) A simultaneous notification process was implemented through the installation of a multipath fax machine; (4) ENN testing by communicators is to begin immediately after emergency declaration, and communicators have been trained to promptly inform the Emergency Director of failure to contact any agency; (5) Emergency Director will initiate emergency notifications immediately after classification and focus on initial notification functions. Georgia agencies have been given increased notification priority.

The licensee implemented its required audit program, but corrective actions were not always timely. The licensee's audit of the emergency program in July 1990, identified telephone directories used by field monitoring teams that were out-of-date and procedures in Emergency Response Facilities (ERFs) that were not the current revisions. Subsequent NRC review of the Emergency Plan and its Implementing Procedures in the ERFs found multiple examples of maintenance and distribution problems. A violation was issued for failure to distribute and maintain current Emergency Plan and Emergency Plan Implementing Procedures.

The annual exercise, which used the Control Room simulator, was conducted on August 1, 1990. The exercise demonstrated that the licensee had the capability to implement the Emergency Plan and Implementing Procedures. The exercise was a full scale participation exercise with the State of Georgia and Savannah River Site participating from their Technical Support Center (TSC) and Emergency Operating Facility (EOF), and included field monitoring teams. The scenario was detailed and fully exercised the response organizations. The ERFs were activated fully within the required activation times. Site assembly and accountability were timely. Classifications were correct and timely by procedure. Notifications were timely, complete, and the licensee followed up the verbal notification using the newly installed multipath fax machine. The exercise critique was thorough and substantive findings were documented for review and correction. No exercise weaknesses were identified.

Two violations were cited.

2. Performance Rating

Category: 3

Trend: Improving

3. Recommendations

It was noted that significant improvements in the emergency response organization and facilities have been made since the March 20, 1990, loss of vital ac power event. The upgrades to and additions of emergency equipment exceed regulatory requirements in many areas.

While licensee performance during the annual drill demonstrated an ability to effectively implement the Emergency Plan Implementing Procedures, the performance deficiencies which occurred during the actual Site Area Emergency are pre-eminent in establishing the evaluation for the SALP period. The Board concluded that a Category 3 rating was most descriptive of performance. An improving trend recognized the utility's corrective actions and subsequent improved performance.

E. Security and Safeguards

1. Analysis

The adequacy of the security force to provide protection for the station's vital systems and equipment was evaluated for this functional area. The evaluation included a Regulatory Effectiveness Review during this assessment period. To determine the adequacy of the protection provided, specific attention was given to the identification and resolution of technical issues, enforcement history, staffing, effectiveness of training, and staff qualifications. The scope of this assessment also included all licensee activities associated with access control, physical barriers, detection and assessment, armed response, alarm stations, power supply, communications, and compensatory measures for degraded security systems and equipment.

The licensee continues to experience difficulties in the control and protection of safeguards information. This was determined to be a programmatic problem, and resulted in a civil penalty ($7,500) issued February 2, 1990. This followed several instances of licensee identified and reported failures to provide adequate protection for safeguards material. As a result of inadequate corrective action and a subsequent licensee-identified and reported instance of failure to adequately secure safeguards material, a second civil penalty ($50,000) was issued June 27, 1990. The licensee has since reported the occurrence of another instance in which safeguards material was left unsecured.

Since the last assessment period, improvement was noted in the areas of training, armed response capability, weapons, and search equipment. However, the licensee has been slow to implement necessary actions to resolve weaknesses in perimeter alarm assessment capability that have been repeatedly identified by the NRC. Testing and evaluations revealed some deterioration in the functional adequacy of the security computers related to call-up time for the assessment of alarms.

During the assessment period, security force management and shift staffing levels were maintained at an acceptable level. Sufficient security personnel were available to meet compensatory posting requirements without excessive overtime expenditures.

The licensee submitted seven changes to its security plans during this SALP period. Of the seven, one change was not consistent with the provisions of 10 CFR 50.54(p). The licensee was responsive to the NRC's concerns regarding the inconsistent change. Overall, the plan revisions were properly documented.

During the assessment period, improvement in the effectiveness of firearms training and qualification was noted, and the routine use of compensatory measures for degraded or inoperative security systems and equpiment was reduced. The licensee's construction and equipping of a secondary access portal with "state of the art" detection equipment is noteworthy.

The onsite review of safeguards events indicated proper licensee identification and reporting.

The Regulatory Effectiveness Review (RER), conducted in April 1990, did not identify any violations of regulatory requirements or any safeguards vulnerabilities.

Four violations were cited.

2. Performance Rating

Category: 3

3. Recommendations

None

F. Engineering/Technical Support

1. Analysis

The Engineering/Technical Support functional area addressed the adequacy of engineering and technical support for all plant activities including activities associated with plant modifications, technical support provided for operations, maintenance, testing and surveillance, outage management, and licensed operator training.

Engineering and technical support performance effectiveness was inconsistent during the assessment period. Site engineering was routinely involved in plant activities, addressed technical issues, and participated in plant event critique teams and daily plant management meetings. A duty engineer was maintained on-call to provide a 24-hour engineering resource availability. Engineering evaluations were typically comprehensive as demonstrated in the Cold Leg Accumulator metallurgical concerns issue and the HVAC equipment seismic monitoring issue. Engineering's Ten-year Interval ISI Program was detailed and demonstrated a thorough understanding of applicable regulatory and industry guidance.

With minor exceptions, engineering demonstrated effective control over the design change process. The modification to resolve reactor vessel mid-loop level indications initially was unacceptable in that, when installed, the local indication could not be read without difficulty. Additional modification was necessary to correct this human factors deficiency. The program for development of minor design changes was effective with the exception of some 10 CFR 50.59 safety evaluations which were not sufficiently detailed. The design process was adequately monitored by the licensee.

Several NRC identified engineering performance deficiencies were noted during this assessment period. Deficiencies with the legibility of critical drawings were identified in the previous assessment period and again this period. Engineering's final corrective actions were thorough. Upon identification of this deficiency, the engineering department immediately reviewed and corrected all critical drawings. The long term corrective action was the initiation of a computer aided drawing system for drawing updates to resolve legibility problems. A second engineering deficiency involved the check valve testing portion of the Inservice Testing (IST) program, where the established criteria for flow verification were inadequate. This weakness indicated the licensee's review of Generic Letter 89-04 was not thorough. Corrective actions included revision of implementing procedures for check valve testing, and an additional review of the Generic Letter positions. A final example of an engineering deficiency involved the technical content of the licensee's resolution to the surge line stratification issue (NRC Bulletin 88-11). Engineering did not identify the potential significance of the difference between the assumed line analysis temperature and the actual measured plant temperature.

During the assessment period, a practice was identified in which a generic procedure was used to calibrate CALCON pneumatic temperature sensors. The procedure did not establish either consistency or repeatability in the calibration process. Failure of CALCON temperature switches has been a recurring problem with the EDG protective trip system, as identified by the IIT. Since the March 20 event, the analysis concerning CALCON switch characteristics has been detailed and effective. EDG reliability has been increased with the isolation of the jacket water temperature signal from the emergency trip system. Isolation of this signal prevents spurious EDG failures stemming from jacket water temperature sensor failure.

Outage management was also noted by the IIT as an area of performance shortcomings. Plant configurations and conditions were allowed to exist during 1R2 that resulted in an unnecessary reduction in safety margin which led to the March 20 event. By planning, scheduling, and conducting outage activities based on the relative risk, the potential loss of the RHR system could have been limited without having a negative impact on the outage duration. Rather than doing this, outage management relied on its TS which contain few requirements for cold shutdown. Electrical power sources were at minimal levels while in mid-loop conditions. Equipment was staged such that the containment equipment hatch could not be closed in a timely manner. Portable equipment refueling procedures were not implemented so as to defend against potential accidents.

Improvements in outage management subsequently occurred following the March 20, 1990 event. These improvements included an increase in the number of available electrical sources used to power Class 1-E emergency buses during periods of Reactor Coolant System (RCS) reduced inventory, conducting an extra drain down of the RCS to midloop during the defueled window to allow for maintenance of RCS valves, providing a monitoring capability for RHR pump cavitation, developing of an electronic transfer of data between the scheduling program and the work order database, and providing a method for closing the containment equipment hatch during loss of all power conditions. Furthermore, the sequence for performing the Engineered Safety Features Actuation System (ESFAS) testing and associated EDG inspections has been moved to the beginning of the outage to include as much safety equipment testing as possible.

An additional area of concern identified during this SALP period was the inadequacy of communications between the various technical departments supporting the plant. The March 20 event displayed this inadequacy in three ways - the use of incore thermocouples by the operating staff which were not indicative of core conditions, the discovery of a construction error on the Unit 2 main turbine differential overcurrent relay setting, and the inability to close the Unit 1 containment equipment hatch as required. This was further exemplified by the NRC identified condition where containment integrity was not maintained during hydrogen analyzer testing. In all three cases, lack of effective interdepartmental exchanges of information were contributing factors to these problems. However, there were instances of effective interdepartmental cooperation. An example was ESFAS testing, where site engineering's involvement in daily management meetings helped enhance communications and allowed the test to be conducted effectively.

During the last assessment period, communications between the corporate engineering staff and the NRC displayed some weaknesses. Since that time, communications have been good. This was demonstrated in the licensee's interface with the NRC on technical issues, including the surge line stratification and the Ten-year Interval ISI Program.

A strong licensed operator training program was demonstrated by the initial and requalification examination results. Initial examinations were administered to 16 Senior Reactor Operators (SROs) with 16 SROs passing. The requalification training program was rated as satisfactory based on a 94 percent pass rate. Six of 6 Reactor Operators (ROs), 10 of 11 SROs, and 4 of 4 crews passed requalification examinations. The simulator was upgraded to resolve modeling deficiencies identified in the previous assessment period. The simulator was on schedule for certification in late 1990.

The actions of the operators during the March 20 event also demonstrated the adequacy of the training program. Core exit thermocouple and water level indications were closely monitored so that core conditions could be evaluated. EOPs and AOPs were effectively used. However, some training deficiencies were identified such as the identification of the cause of the EDG trips and the local operation of the sequencer. In addition, licensed and non-licensed operators and the plant engineers did not understand the operation of all EDG systems under abnormal conditions.

No violations were cited.

2. Performance Rating

Category: 2

3. Recommendations

None

G. Safety Assessment/Quality Verification

1. Analysis

This functional area addressed the licensee implementation of safety policies, activities related to license amendments, exemptions, relief requests, responses to Generic Letters, Bulletins, and Information Notices, resolution of safety issues (10 CFR 50.59 reviews), safety review committee activities and the use of feedback from self-assessment programs and activities. It included the effectiveness of the licensee's quality verification function in identifying and correcting substandard or anomalous performance, in identifying precursors for potential problems, and in monitoring the overall performance of the plant.

The Plant Review Board (PRB), established to advise the General Manager on all matters related to nuclear safety, performed its intended function and carried out its designated responsibilities. One improvement implemented late during the previous assessment period and reviewed this period was the membership in the PRB. The PRB was upgraded such that department managers replaced supervisors as the PRB members. The Assistant General Manager - Plant Operations was appointed as chairman of the PRB. This change was considered a strength.

The Safety Audit and Engineering Review (SAER) group performed audits of the Vogtle quality assurance program and conducted activity oriented evaluations of specific work practices such as control room turnovers, surveillance testing, maintenance testing and refueling outage activities. These activities were effective and resulted in the identification of numerous significant issues. Issues identified included an invalid American Society of Mechanical Engineers (ASME) Section XI valve stroke time test, a failure to properly calibrate plant computer data points for the primary precision heat balance resulting in an inadequate surveillance, and valid diesel generator failures not being recorded and evaluated as required by plant TS. Each of these issues resulted in a Licensee Event Report (LER) or NRC required special report.

The SAER group manager and site supervisor are licensed SROs. Other SAER personnel have received training in Pressurized Water Reactor (PWR) systems similar to that received by plant engineering personnel. All site auditors are certified lead auditors pursuant to the American National Standards Institute (ANSI) standards. The SAER group also called upon technical experts to assist with selected audits. Staffing of this group is adequate.

Longstanding problems were not always recognized and corrected. One example involved sticking starting air valve pistons on the diesel. On at least five occasions during this assessment period, the diesel generators failed to start on a non-emergency start. The licensee was slow in recognizing that there was a problem with the diesels and determining the cause. The licensee's investigation into the problem finally determined that there was a manufacturing deficiency in the air start system that could allow the starting air valve pistons to stick. As a result of this investigation the manufacturer issued a 10 CFR Part 21 report.

The licensee's corrective action program was seen as a significant programmatic shortcoming in the previous assessment period. Licensee management recognized the identification of root causes and the slow or ineffective implementation of corrective actions as a weakness and focussed attention in this area. Actions in this area included training personnel in root cause analysis, improving guidance in root cause determination and the identification of corrective action, establishing formal interdisciplinary event critique teams and improving the deficiency card program. However, this improvement effort is an ongoing process and has not reached its full potential.

The licensee's self-assessment activities resulted in several licensee identified violations of NRC requirements. This indicated a strong program whose goal was to ensure that appropriate compliance was maintained.

Radiological control audits performed by the onsite Quality Assurance audit organization were generally complete, timely, and thorough. During the last assessment period, the quality of the audits in the area of radioactive waste control was identified as a weakness. This aspect of the licensee's program improved significantly in that the audits were found to be well planned and contained items of substance relating to the radwaste and transportation programs.

The LERs adequately described all of the major aspects of the reported events, including component or system failures that contributed to the events and the significant corrective actions taken or planned to prevent recurrence. The reports were well written and, generally, provided the reader with enough information to readily understand the events. Previous similar occurrences were referenced as appropriate. The licensee submitted updates to the LERs when needed.

Licensee proposals and responses were generally well prepared, accurate, and thorough. Examples of such responses included the response to Generic Letters 89-13 (Service Water Systems) and 89-08 (Erosion/Corrosion), and Bulletins 89-03 (Shutdown Margin during Refueling) and 88-10 (Molded Case Circuit Breakers) . In support of licensing activities, the licensee's submittals concerning technical and safety issues was consistently good. Submittals reflected a clear understanding of the technical and regulatory issues involved, and the approach to the resolution of these issues was consistently conservative. The licensee's assessment of the impact of Generic Letters and Bulletins on the plant resulted in timely responses. The licensee expeditiously processed the TS amendment application to support their waiver of compliance request to manually bypass the EDG high jacket water temperature sensors, and subsequently implemented the plant modification and performed the associated EDG testing in a timely fashion.

Two violations were cited.

2. Performance Rating

Category: 2

3. Recommendations

None

V. SUPPORTING DATA AND SUMMARIES

A. Licensee Activities

During this assessment period, Unit 1 completed a scheduled refueling outage of 56 days duration. This unit experienced a loss of vital ac power on March 20, 1990, while the plant was in cold shutdown as discussed in Section IV.A. Short duration power reductions or forced outages occurred due to repair of a steam leak on a main feedwater pump, heater drain pump and valve maintenance, and turbine vibration problems.

Unit 2 initiated coastdown on June 14, 1990, in preparation for its first refueling outage. The reactor was manually tripped on September 14, 1990. The planned outage duration of 50 days was extended due to fuel handling machine problems and retaining ring main generator difficulties. Forced outages and reduced power levels were caused by heater drain tank pump and level control problems.

B. Direct Inspection and Review Activities

In addition to the routine inspections performed at the Vogtle facility by the NRC staff, special inspections were conducted as follows:

- March 23 - June 8, 1990; Incident Investigation Team concerning the Unit 1 loss of vital ac power event on March 20, 1990.

- April 9-16, 1990; RER (Physical Security) Inspection
- May 7-18, 1990; Emergency Operating Procedure Inspection

- July 30 - August 3, 1990; Emergency Preparedness Exercise Evaluation

- August 6-17, 1990; Special team inspection of operational safety

C. Management Conferences

December 11, 1989; Enforcement Conference at Region II to discuss protection of safeguards material.

February 26, 1990; Management meeting in Rockville, Maryland, to discuss problems regarding thermal stratification in the pressurizer surge line.

May 22, 1990; Enforcement Conference in Region II to discuss the circumstances of an unsecured safeguards container on April 25, 1990, and accountability and control of safeguards documents.

September 5, 1990; Enforcement Conference in Region II to discuss numerous items identified by the Incident Investigation Team which was chartered in response to the Site Area Emergency event of March 20, 1990.

D. Confirmation of Action Letters

A Confirmation of Action Letter (CAL) was issued March 23, 1990, as a result of the March 20, 1990, SAE event. The licensee agreed to cooperate with the IIT and take actions necessary to support this investigation. The commitments identified in the CAL included the concurrence of the Regional Administrator prior to Unit 1 power operation, equipment quarantine, preservation of records or damaged equipment, availability of plant personnel for questioning, conduct of separate investigations. The licensee was fully responsive to the CAL issues, and was released from the CAL on July 20, 1990.

E. Review of Licensee Event Reports (LER)

During the assessment period 37 LERs were analyzed. The distribution of these events by cause as determined by the NRC staff was as follows:

Cause	Totals	Unit 1	Unit 2
Component Failure	7	2	5
Design	2	0	2
Construction/Fabrication Installation	1	1	0
Personnel			
- Operating Activity	9	7	2
- Maintenance Activity	5	4	1
- Test/Calibration Activity	9	5	4
- Other	1	1	0
Other	3	1	2
Totals	37	21	16

Notes:
1. With regard to the area of personnel, the NRC considers lack of procedures, inadequate procedures, and erroneous procedures to be classified as personnel error.
2. The Other category is comprised of LERs where there was a spurious signal or a totally unknown cause.
3. Eight LERs were submitted as security and safeguards LERs, and are not included in the above tabulation.
4. The above information was derived from a review of LERs performed by the NRC staff and may not completely coincide with the licensee's cause assignments.

F. Licensing Activities

In support of licensing activities various communications were maintained with the licensee. These consisted of meetings, telephone and written correspondence. There have been approximately 91 active licensing actions for the Vogtle units during this evaluation period of which 56 were completed. Of these, 23 were license amendments.

G. Enforcement Activity

Functional Area	No. of Deviations and Violations in Each Severity Level (Unit 1/Unit 2) Dev.	V	IV	III	II	I
Plant Operations			3/3			
Radiological Controls						
Maintenance/Surveillance			3/3			
Emergency Preparedness			1/1		1/1*	
Security			3/2	1/1		
Engineering/Technical Support						
Safety Assessment/Quality Verification			1/2			
TOTAL	0/0		11/11	1/1	1/1	

*Issued after the assessment period.

A Severity Level II violation in the area of Emergency Preparedness was issued on October 19, 1990, involving failure to make emergency notifications to state and local authorities within 15 minutes after the declaration of an emergency. ($40,000 Civil Penalty)

A Severity Level III violation in the area of Security and Safeguards was issued on June 27, 1990, for failure to follow 10 CFR Part 73 and an Administrative Procedure in that a safeguards information storage cabinet containing approximately 140 safeguards information documents, including the site Physical Security and Contingency Plan, was found unsecured and unattended. ($50,000 Civil Penalty)

A Severity Level IV violation in the area of Security and Safeguards was issued on February 2, 1990, for failure to properly protect and account for documents containing Safeguards Information. ($7,500 Civil Penalty)

H. Reactor Trips

This summary includes the unscheduled manual and automatic reactor trips that have occurred since the beginning of the SALP period, October 1, 1989.

Unit 1

July 23, 1990 - The unit was manually tripped from 100% power in anticipation of low-low steam generator level. This resulted from an internal fault experienced on a non-1E, 4160-volt to 480-volt transformer which caused a loss of power to the speed control circuitry for the main feedwater pump turbines. This in turn caused a loss of both main feedwater pumps. Steam generator water levels had decreased to 24% (narrow range) when the operator initiated a manual trip.

April 25, 1990 - The unit was manually tripped from 87% power in anticipation of low-low steam generator level. This occurred when local maintenance workers accidentally shut off the control air to a main steam isolation valve (MSIV) causing the valve to close.

January 24, 1990 - An automatic reactor trip from 90% power occurred on low steam generator level caused by fast closure of an MSIV during a partial stroke test. When a jumper was installed in accordance with the test procedure, the MSIV control fuses failed.

October 2, 1989 - An automatic reactor trip from 100% power occurred on low-low steam generator when an MSIV inadvertently closed. The licensee determined that a ground on an MSIV limit switch caused a fuse in the MSIV control circuitry to blow, which in turn resulted in a loss of power to the MSIV solenoid valve and the subsequent closure of the MSIV.

Unit 2

June 30, 1990 - The unit was manually tripped from 18% power in anticipation of decreasing levels in the steam generators due to inadequate feedwater control during low power operation.

June 28, 1990 - The unit was manually tripped from 87% power when an MSIV drifted closed following an O-ring failure and subsequent loss of hydraulic fluid.

May 6, 1990 - An automatic reactor trip from 100% power occurred on low-low steam generator level due the closure of an MSIV. This was the result of a failure in the AX1 relay which energizes both the air supply solenoid and the hydraulic pump solenoid to allow the MSIV to remain open.

March 20, 1990 - An automatic trip from 100% power occurred due to a turbine trip on an electrical fault.

December 2, 1989 - An automatic trip from 100% power followed a turbine trip when a heater drain tank level control valve reassembly error led to a high level in a moisture separator reheater.

November 5, 1989 - The unit was manually tripped from 100% power due to decreasing level in the steam generators after the loss of the "B" main feedwater pump. The licensee was returning the heater drain tank level control valve (high level dump valve to the hotwell) to service after packing replacement. The valve opened for unknown reasons and resulted in lowering main feedwater pump suction pressure. The standby condensate pump failed to start, and subsequently, the "B" main feedwater pump tripped on low suction pressure.

October 11, 1989 - An automatic reactor trip from approximately 58% power occurred on high neutron flux rate when a rod dropped because a diode failed on a rod gripper control card.

RESOLUTION ITEM TRACKING
MASTER REPORT

#	RESP	MSSS BOP	DATE IDENT	DATE DUE	DATE RESOLVED	DESCRIPTION	STATUS
11	ALL		12/01/87	01/04/88	/ /	IDENTIFY NUMBER AND TYPE OF CONTRACTOR ASSISTANCE REQUIRED.	memo issued to all departments.
25	MAINT		12/01/87	01/04/88	/ /	DETERMINE UNDERWATER INSPECTION REQUIREMENTS, ISSUE MATL. REQ. DIVER SERV.	
1	ENGR		12/01/87	01/14/88	/ /	DETERMINE SCOPE OF ISI PROGRAM.	
5	CHEM		12/01/87	01/14/88	/ /	DETERMINE WHAT INSPECTIONS TO BE PERFORMED ON FW HEATERS & MSR'S	
24	ENGR		12/01/87	01/14/88	/ /	SNUBBER TESTING SCOPE AND PLAN	
15	ENGR		12/01/87	01/15/88	/ /	DETERMINE SCOPE OF SWITCHYARD TRANSFORMER WORK	DOBLE TEST BY ATLANTA, XFMR oil & some relay work.
19	MAINT		12/01/87	01/15/88	/ /	DETERMINE IF ANY MOCK-UP TRAINING IS NEEDED.	
21	ALL		12/01/87	01/20/88	/ /	IDENTIFY OUTAGE SURVEILLANCES/COMMITTMENTS REQUIRING COMPLETION IN OUTAGE.	
7	MAINT		12/01/87	01/30/88	/ /	SCOPE OF LIVE LOAD PACKING PROGRAM IF ANY.	
8	MAINT		12/01/87	01/30/88	/ /	DETERMINE SCOPE OF MOVATS TESTING FOR SCHEDULE IMPACT.	
14	ADMIN		12/01/87	01/30/88	/ /	DEVELOP PERSONNEL ACCESS SCREENING AND TRAINING PROGRAM & SCHEDULE	
16	SCHED		12/01/87	01/30/88	/ /	DETERMINE TEMPORARY TRAILER NEEDS AND LOCATION	
17	MAINT		12/01/87	01/30/88	/ /	ARRANGE RADIOGRAPH SERVICES IF REQUIRED. HAVE CONTRACT IF NEED ARISES.	
18	HP		12/01/87	01/30/88	/ /	DEVELOP PLAN ON HANDLING TOOLS, EQUIP., ETC. FOR DECONTAMINATION.	
23	TRAINING		12/01/87	01/30/88	/ /	MINIMIZE TRAINING DURING OUTAGE FOR PERSONNEL INVOLVED IN OUTAGE	
27	MATERIALS		12/01/87	01/30/88	/ /	MATERIAL RESERVATION, STAGING, LOCATION	
30	SECURITY		12/01/87	01/30/88	/ /	INTERIM ACCESS	
33			12/01/87	01/30/88	/ /	SCOPE DEVELOPMENT AND PRE-OUTAGE PLAN	
3	ENGR		12/01/87	01/31/88	/ /	WHO IS GOING TO PERFORM TG WORK. ISSUE BID REQUESTS?	maint. will probably use contractor.
22	SCHED		12/01/87	03/01/88	/ /	PREPARE PRELIMINARY SCHEDULE	
26	ENGR		12/01/87	04/01/88	/ /	CONTROL ROD WEAR INSPECTION. WHAT IS REQUIRED?	
6	NSAC		12/01/87	/ /	/ /	DETERMINE AND REGULATORY COMMITTMENTS TO BE IMPLEMENTED	
32			12/01/87	/ /	/ /	NPHIS	
35			12/01/87	/ /	/ /	LESSONS LEARNED	
36			12/01/87	/ /	/ /	DERIVATION OF OUTAGE ACTIVITY DURATIONS	

RESOLUTION ITEM TRACKING
MASTER REPORT

ITEM #	RESP	NSSS BOP	DATE IDENT	DATE DUE	DATE RESOLVED	DESCRIPTION	STATUS
2	ENGR		12/01/87	12/17/87	12/17/87	DETERMINE SCOPE OF TURBINE-GENERATOR WORK.	resolved per McLeod ltr 6/24/87
4	MAINT		12/01/87	12/17/87	12/17/87	DETERMINE SCOPE OF PM PROGRAM TO BE PERFORMED.	IRI will include some 36 & 54 mo. p.m.'s
9	ENGR		12/01/87	12/17/87	12/17/87	REVIEW AND REVISE PROCEDURE FOR DISASSEMBLY OF R.V. HEAD FOR GOOD COORD.	
10	ENGR		12/01/87	12/17/87	12/17/87	DETERMINE TYPE AND ACQUIRE SOME BASIC UNDERWATER RETRIEVAL TOOLS.	MATERIAL PROC. INITIATED
12	ENGR		12/01/87	12/17/87	12/17/87	DETERMINE SCOPE OF EDDY CURRENT TESTING & ISSUE CONTR. SERVICES REQUEST	Specific RFQ's for S/G EC test issued.
13	ENGR		12/01/87	12/17/87	12/17/87	ISSUE SLUDGE LANCE CONTRACTOR SERVICES REQUEST	
20	CHEM		12/01/87	12/17/87	12/17/87	IS HYDROGEN PEROXIDE ADDITION TO BE DONE?	RCS will receive hydrogen peroxide treatment.
28	ENGR		12/01/87	12/17/87	12/17/87	REFUELING OFF LOAD PLAN	Method will be complete offload.
29	ENGR		12/01/87	12/17/87	12/17/87	STEAM GENERATOR WORK OTHER THAN PREVIOUSLY IDENTIFIED	None.
31	ENGR		12/01/87	12/17/87	12/17/87	DCP FRAGNETS	Priliminary fragnets prepared by Outage & Sched.
34			12/01/87	12/17/87	12/17/87	P/2 USEAGE IN PRE-OUTAGE PLAN	P/2 will be used for pre-outage plans.

Interoffice Correspondence Georgia Power

DATE: April 18, 1988

RE: Plant Vogtle - Units 1 & 2
Refueling Outage Meeting
Minutes (April 14, 1988)

FROM: J. F. D'Amico

TO: J. B. Beasley

The biweekly Refueling Outage Meeting was held on Thursday, April 14, 1988 at 11:00 AM. The following is a summary of topics discussed.

Ron Bush, Engineering, discussed the Spent Fuel Rack Project. His handout (attached) includes a schedule of project milestones, a list of involved personnel and the current approved schedule for fuel rack installation. Also included is the proposed schedule which was developed when we learned of the delay in delivery of racks number 7 and number 8. Spencer Semmes noted that contingency planning still allows for fuel receipt beginning on July 18, 1988, with at least four racks in the fuel pool.

Indira Kochery, Health Physics, explained the requirement that all contractors arriving on-site must provide acceptable, signed reports of prior occupational radiation exposure history. Otherwise, their exposure at Vogtle will be limited to 1 Rem per quarter.

Elijah Dixon, Building and Grounds, presented his recommendations for Turbine Building Washdown (see attachment). Outage Planning will take the lead on determining feasibility and schedule restraints for this task.

Joe D'Amico stated that Chemical Clean-Up will take place at mid-loop and will take 2 1/2 to 3 days.

Two lists of Surveillances were distributed to the attendees. The first is a list of those Surveillance Tasks which are currently planned for the first refueling outage. The second is a list of all the Surveillance Tasks which have a late date prior to June 2, 1990, (prior to the second refueling outage). The attendees were asked to compare the two lists and identify any items which should be added to the first refueling outage. Please address comments to Lori Potts at extension 4288 or Marty Haase at extension 3164.

Joe D'Amico presented a list of new activities added to the outage schedule during the past week (attached). He stated that he intends to distribute a similar list at subsequent outage meetings for all activities added since the last meeting. He will add the estimated manpower for each activity to this list if it is deemed necessary.

James Sutphin, I&C, briefly described the I&C plan to identify PM's required for the first refueling outage. He plans to look at the PM's coming due within the next 12 months and expects to begin producing results by April 21, 1988. He anticipates completion of this project by May 15, 1988.

Work Planning and Outage Planning will get together to develop a method to prioritize the packaging effort for PM and Corrective Work Orders.

Seven items on the Resolution Item Tracking List (attached) were discussed as follows:

Number 7 Live Load Packing Program - Ric Blaine said the DCP is currently at PFEO. The scope includes approximately 10 BOP valves, many of which are in the condenser area. Questions will be resolved and the package will be out of PFEO by April 28, 1988.

Number 26 Control Rod Wear Inspection - Don Williams said the package is currently held up by the Reactor Engineering Supervisor.

Number 40 Containment Spray Miniflow Concerns - Ric Blaine said he is awaiting a response from PFEO on the RER. The resolution will entail imposing an administrative control on the duration of pump run during ESFAS testing. Formal resolution expected by 5/15/88.

Number 67 Additional TGV Guidelines - Art Caudill stated response is due back from PFEO by 4/16/88.

Number 70 RER For Demin Valve 1418-U8-005 - Mark Biron said the RER Number would be available the afternoon of 4/14/88.

Number 78 Turbine Building Bridge Crane - Ric Blaine stated that two REA's have been sent to PFEO with response anticipated within three weeks. One REA is to upgrade the limit of the Unit 1 crane, the other is to determine the allowable period of time during which both cranes may be on one side of the building.

Number 6 Determine Regulatory Committments - Terry Wendt said comments are due back 4/22/88 on the letter to all departments requesting input.

Items brought up during the open discussion portion of the meeting were:

- If the AMSAC/Core Drill can be performed within a six day window, the question of control room pressurization will be satisfied.
- Any Schedule information received in bid packages should be immediately forwarded to Marty Haase/Wren Stevenson.
- An anchoring device will be required during removal of the generator rotor. This will be added to the Resolutions Item Tracking List.
- Bill Lamkin/John Qualizza need to know requirements for laydown areas in containment as well as polar crane usage.

- The Breathing Air question has been resolved. The skid unit (under a Temp Mod) will be the primary source and service air (with filters) will be the secondary source.

- Supervisors need to let their people know that up-to-date refueling and pre-outage schedules are available for their use and comments. The schedules are issued for the purpose of generating feed-back and information. Please let Outage Planning know if you would like additional information, or the same information in a different format.

The next Refueling Outage Meeting is scheduled for April 28, 1988, at 11:00 A.M. in the Outage War Room.

LAP/cjb

Attachments

xc: Attendees
Refueling Outage Status Contacts

ATTENDEE LIST

	NAME	DEPARTMENT	PHONE EXT.
1.	Wren Stevenson	O&P	4470
2.	Dinos Nicolaou	O&P	3236
3.	Don Deisley	O&P	3205
4.	Phillip L. Cupp	O&P	4212
5.	Allen Cure	HP	4474
6.	Mark Biron	HP	4362
7.	Robert Gunn	Sec.	4111
8.	Tony Prestifilippo	Eng.	3869
9.	Doug Akin	Admin.	3496
10.	Daryl T. Glover	Work Planning	4422
11.	Jerry Martin	Work Planning	3577
12.	Jerry Greenwood	Westinghouse (SSM)	4176
13.	Michael Cortese	O&P/MDSG	4139
14.	T. B. Lunsford	Materials	3950
15.	Indira Kochery	HP	3229
16.	S. P. Green	Maintenance	3487
17.	Tim Austin	Training	3315
18.	Art Caudill	Eng. Suppt.	4124
19.	Steve A. Phillips	Maint.	3469
20.	Dusty Rhodes	O&P	3269
21.	Jennifer Bates	NPFSG	3595
22.	S. Swanson	O&P	3812
23.	A. A. Simmson	Q.C.	3293
24.	Darrell Barnett	Maintenance	3190
25.	E. L. Kellum	Maintenance	3481
26.	Hank Thompson	Maintenance	3899
27.	Terry Wendt	NSAC	3178
28.	Mike Lackey	WPG	4175
29.	Tom Mundy	WPG	3860
30.	John Qualizza	O&P	3173
31.	Ron Bush	GPC	8-526-7159
32.	D. O. Williams	Reactor Eng.	4144
33.	Rick Barlow	Operations	3497
34.	David Seckinger	MT	3474
35.	Jim Montgomery	G.E. Co.	3513
36.	Ric Blaine	Eng. Support	3162
37.	Joe Fehrenbach	Unit 2 Sched.	1517
38.	David McCary	O&P/MDSG	4142
39.	Fred Warren	O&P/MDSG	39[illegible]9
40.	Cromwell Stone	O&P/MDSG	3450
41.	W. A. Lamkin	O&P/MDSG	4114
42.	J. B. Beasley	O&P	4209
43.	M. R. Haase	O&P	3164
44.	J. F. D'Amico	O&P	3139
45.	Lori Potts	O&P	4288
46.	S. Semmes	Eng.	4346
47.	E. Dixon	B&G	3727
48.	James Sutphin	I&C	3181

REFUELING OUTAGE STATUS CONTACTS

DEPARTMENT	DEPARTMENT CONTACT	EXT.	BEEPER
OUTAGE PLANNING	Tim Adams	3198	823-7564
	Wren Stevenson	4470	
	Dusty Rhodes (BOP)	3259	828-9405
	John Qualizza (NSSS)	3173	
PS&WC	Jerry Martin	3577	
MOSG	Fred Page	4172	
MAINTENANCE	Steve Phillips	3469	
I & C	Mike Hobbs	3174	
OPERATIONS	Bill Burmeister	3286	
HP	Ken Petrosky	4018	
	alt. Allen Cure	3871	
CHEMISTRY	Rich Tupper	4135	
ENGINEERING	Ric Blaine	3162	
REACTOR ENG.	Don Williams	4144	
NPSFG	Jennifer Bates	3595	
QC	Rich Heitz	3293	
NSAC	Terry Wendt	3178	
TRAINING	Mike Kurtzman	3354	
	alt Russell Brown	3353	
SECURITY	Sid Walker	3514	
ADMIN	Doug Akin	3496	
PROCUREMENT	Terry Lunsford	3950	233

FUEL RACK PROJECT MILESTONES

AUGUST 1987	-CONTRACT SIGNED FOR 20 RACKS FOR WEST POOL (CBI SERVICES
NOVEMBER 1987	-1ST LICENSING SUBMITTAL (SEISMIC AND CRITICALLITY)
JANUARY 1988	-2ND LICENSING SUBMITTAL (SN M LICENSE)
APRIL 1988	-3RD LICENSING SUBMITTAL (FUEL POOL COOLING)
JUNE 1988*	-DELIVERY OF RACKS 1 THRU 8
JUNE 1988	-INSTALLATION OF RACKS 1 THRU 8
NOV 1988	-DELIVERY OF RACKS 9 THRU 20
1989	-INSTALLATION OF RACKS 9 THRU 20

*CBI HAS SCHEDULED DELIVERY OF RACKS 9 THRU 12 THIS YEAR ALTHOUGH CONTRACT ALLOWS FOR INCREMENTAL SHIPMENT DATES OF SEPT 1988, APRIL 1989 AND NOV 1989.

FUEL RACK PROJECT

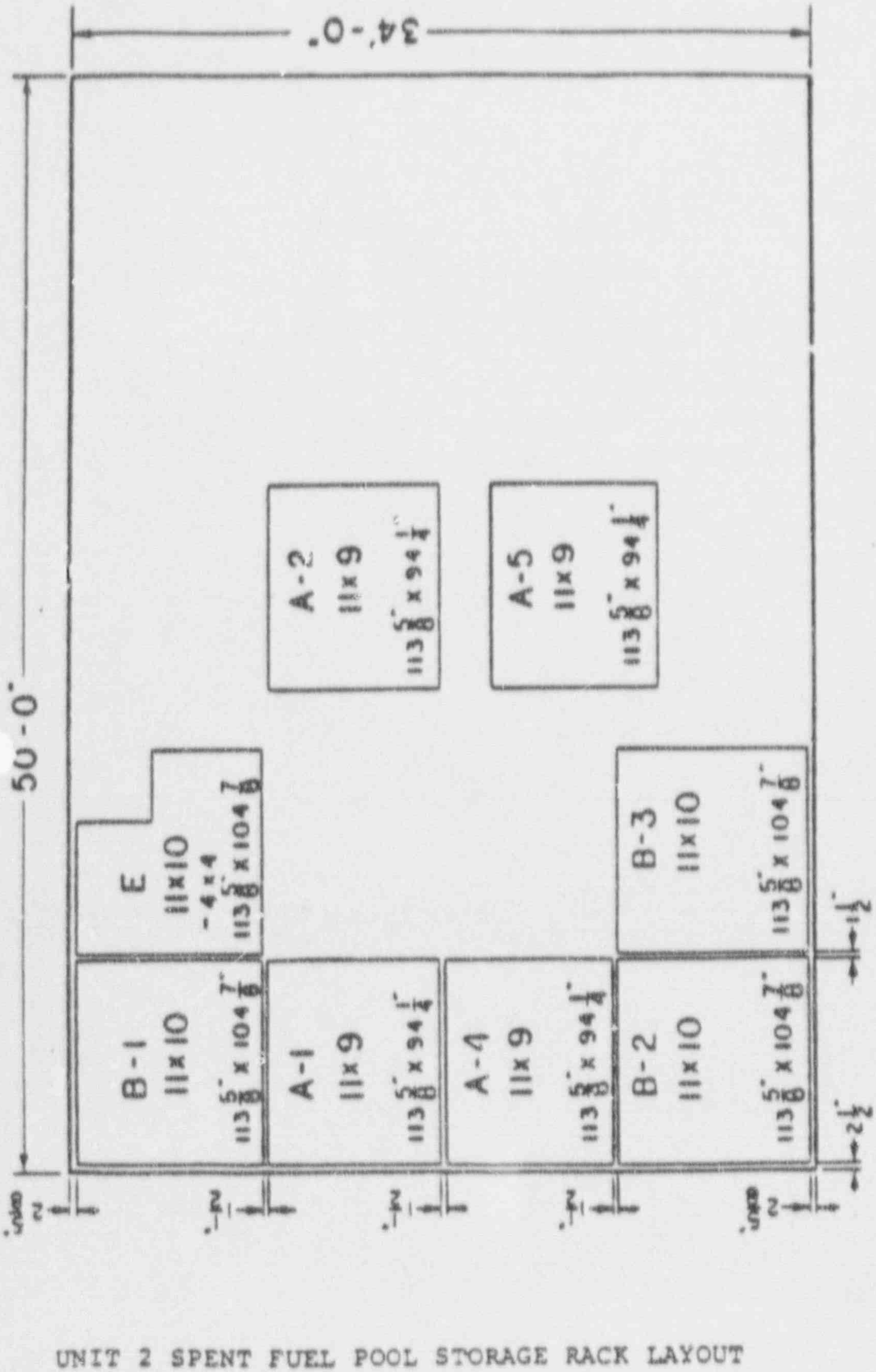
PRIMARY CONTACTS

PROJECT MGR.	RON BUSH	GPC	8-526-7159
DESIGN ENGINEER	ARTURO CORRAL	BECHTEL	7757
SYSTEM ENGINEER	SPENCER SEMMES	GPC	4346
EXPEDITER	OMAR SMITH	SCS	7666
INSTALLER	MIKE CAGLE	PULLMAN	7430
LICENSING	PHIL GRISSOM	SCS	7774
CBI PROJ MGR.	DICK CONWAY	CBI	815-933-2200

ADDITIONAL CONTACTS

NUCLEAR SAFETY	HARRY MAJORS	SCS	6495
NUCLEAR FUELS	RON COCHERELL	SCS	7350
LICENSING	JOHN HARTKA	GPC	7113
FUEL HANDLING	TON WILLIAMS	WESTINGHOUSE	4144
MATERIALS ENG	DAVE CARLSON	BECHTEL	7170
FIELD ENGINEER	ED WILCOX	BECHTEL	7356
NUCLEAR ENG	TJERI SURJANTO	SCS	7244
CIVIL ENG	JOE KASSAS	BECHTEL	7247
CIVIL ENG	RAMESH DUA	SCS	5839
ENGINEERING MGR.	BILL RAMSEY	SCS	7916
LICENSING MGR.	JIM BAILEY	SCS	7912

SNM LICENSE APPLICATION FIGURE 1.2-4



UNIT 2 SPENT FUEL POOL STORAGE RACK LAYOUT

PROPOSED

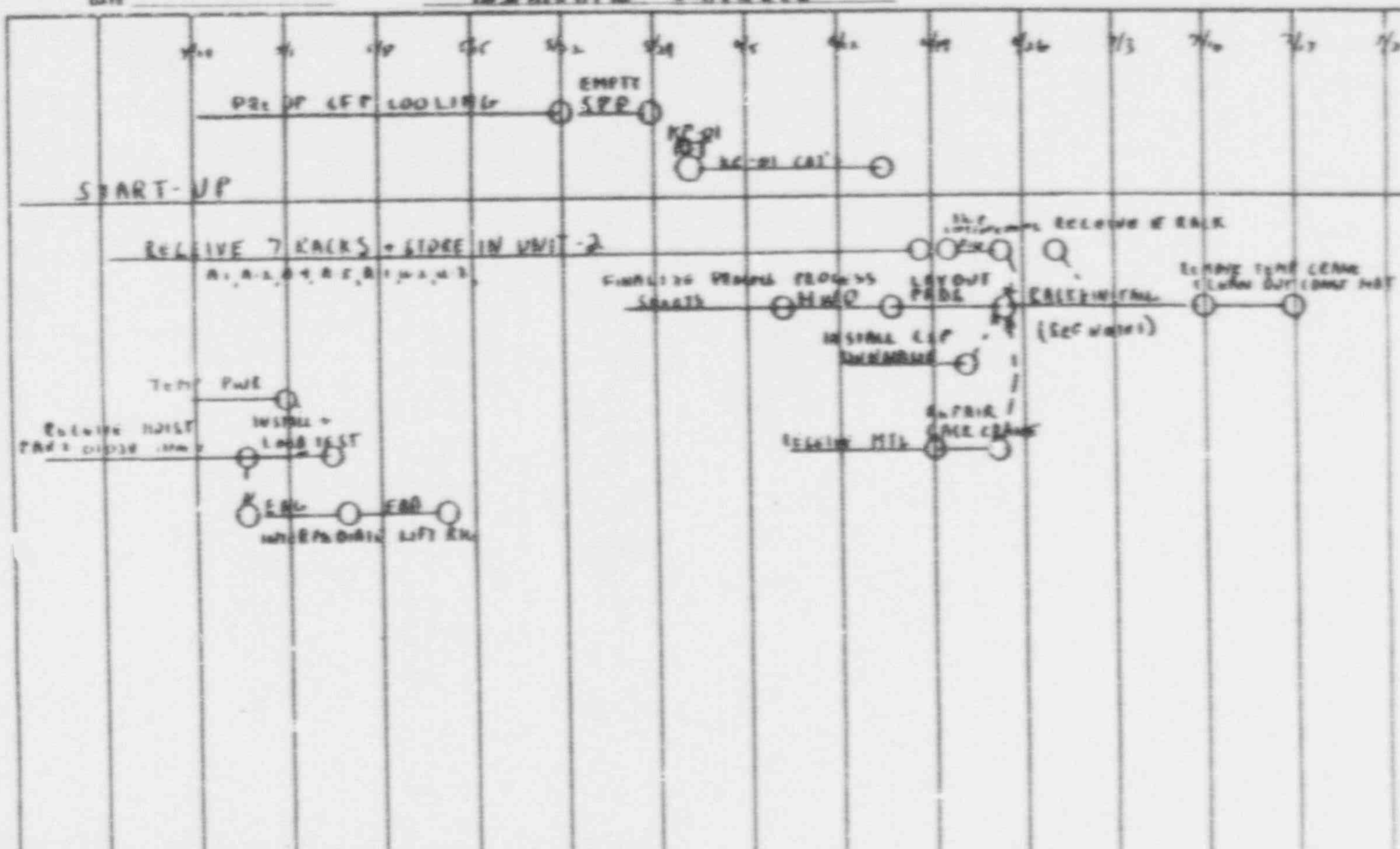
SHEET ____ OF ____

JOB NO. ____

BY ____

DATE ____

UNIT 2 SPENT FUEL RACK INSTALLATION SCHEDULE



SPECIAL REQUIREMENTS

A WITH RACKS STORED IN ... EXPEDITED ENTRY INTO UNIT - REQUIRED

B SCHEDULE HEAVY IN OPERATION ... AND 2 HR TURNAROUND OF RESULTS

NOTES :

1) PLAN IS TO UPEND, WASH AND MOVE 4 RACKS INTO BAY - 1RACK ON THE CLP COVER - 1DAY/3DAYS TO SET & ROUGH LEVEL 4RACKS

2) NEXT 4 RACKS SAME AS 1 ABOVE

3) PULL OUT 3 RACKS TO CENTER POOL & LEVEL

4) FINAL LEVEL 8 RACKS

5) CLP - CASK LOADING PIT

TURBINE BUILDING WASHDOWN

Purpose:	To rid Turbine Building of accumulated dirt, debris and dust that can't be reached by any other methods.
Method:	Service Water — Starting at Level 5 and washing down to each lower floor.
Time:	24 hours to wrap and waterproof electrical equipment and motors. 24 hours for actual washdown.
Work Plan:	Coordinate with Operations, [illegible] and Maintenance Shop as to what equipment, supplies, etc., need to be waterproofed. (wrapped with plastic and taped)
Work Force:	3 Electrical Personnel — 3 Test Shop Personnel. B&G will supply additional personnel to work with these groups.
Safety Concerns:	All non-essential electrical equipment to be de-energized. Notice posted for actual date of washdown, advising personnel of falling debris and water. A requirement of eye protection to be posted.

******* NEW ACTIVITIES ADDED DURING WK OF 4/6-4/12 *********

724611101	'MAIN TURB BACK-UP OVERSPEED TEST & CHANNEL CAL	' 24	
724613101	'TRN A SAFETY FEATURES SEQUENCER U3001 CHAN CAL	' 24	
724614101	'TRN B SAFETY FEATURES SEQUENCER U3002 CHAN CAL	' 24	
724616101	'TURB IMPULSE CHAMBER PRESSURE PROTECT P505 CAL	' 8	
724616102	'TURB IMPULSE CHAMBER PRESSURE PROTECT P505 ACOT	' 4	
724617101	'TURB IMPULSE CHAMBER PRESSURE PROTECT P506 CAL	' 8	
724617102	'TURB IMPULSE CHAMBER PRESSURE PROTECT P506 ACOT	' 8	
724701101	'RCP #1 OVERCURRENT RELAYS 250/251M CHANNEL CAL	' 12	
724702101	'RCP #2 OVERCURRENT RELAYS 250/251M CHANNEL CAL	' 12	
724703101	'RCP #3 OVERCURRENT RELAYS 250/251M CHANNEL CAL	' 12	
724704101	'RCP #4 OVERCURRENT RELAYS 250/251M CHANNEL CAL	' 12	
724706101	'RCP #1 GROUND PROTECTION RELAYS 250/251GM CAL	' 10	
724707101	'RCP #2 GROUND PROTECTION RELAYS 250/251GM CAL	' 10	
724708101	'RCP #3 GROUND PROTECTION RELAYS 250/251GM CAL	' 10	
724709101	'RCP #4 GROUND PROTECTION RELAYS 250/251GM CAL	' 10	
724701101	'RCP #1 OVERCURRENT RELAYS 250/251M CHANNEL CAL	' 12	
724702101	'RCP #2 OVERCURRENT RELAYS 250/251M CHANNEL CAL	12	
724703101	'RCP #3 OVERCURRENT RELAYS 250/251M CHANNEL CAL	' 12	
724704101	'RCP #4 OVERCURRENT RELAYS 250/251M CHANNEL CAL	' 12	
724706101	'RCP #1 GROUND PROTECTION RELAYS 250/251GM CAL	' 10	
724707101	'RCP #2 GROUND PROTECTION RELAYS 250/251GM CAL	' 10	
724708101	'RCP #3 GROUND PROTECTION RELAYS 250/251GM CAL	' 10	
724709101	'RCP #4 GROUND PROTECTION RELAYS 250/251GM CAL	' 10	
755010101	'CONTAINMENT SPRAY SYSTEM LEAKAGE ASSESSMENT	' 4	-
755011101	'CVCS LEAKAGE ASSESSMENT	' 4	-
755012101	'RHR SYSTEM LEAKAGE ASSESSMENT	' 4	-
755016101	'SI SYSTEM LEAKAGE ASSESSMENT	' 4	-
724810101	'DELTA T/T AVG LOOP 1, CHAN I, T-411 CHANNEL CAL	' 36	-
724811101	'DELTA T/T AVG LOOP 2, CHAN II, T-421 CHANNEL CAL	' 36	-
724812101	'DELTA T/T AVG LOOP 3,CHAN III, T-431 CHANNEL CAL	' 36	-
724813101	'DELTA T/T AVG LOOP 4, CHAN IV, T-441 CHANNEL CAL	' 36	-
724901101	'TRN A SAFETY FEATURES SEQUENCER U3001 RST	' 18	-
724902101	'TRN B SAFETY FEATURES SEQUENCER U3002 RST	' 18	-
724676101	'REACTOR VESSEL LEVEL TRANSMITTER CALIBRATION	' 30	-
724518103	'RX COOLANT PRESSURE (WR) P-403 ACOT	' 4	-
724519103	'RX COOLANT PRESSURE (WR) P-405 ACOT	' 4	-
724831101	'RX TRIP & ESF LOGIC (PROCESS & PROTECTION) RST	' 8	-
724839101	'RCP UNDERVOLTAGE RELAYS SENSOR RST	' 4	-
724520101	'RCS SUBCOOLING MARGIN MONITOR CALIBRATION	' 8	-
724539101	'PRESSURIZER PRESSURE CONTROL P-455 CHANNEL CAL	' 8	-
754812101	'2 CHANNEL RX TRIP SYS RESPONSE TIME SUMMATION	' 8	-
724910101	'PASS GASEOUS LEAKAGE ASSESSMENT	' 12	-
728835101	'TRN A H2 RECOMBINER VISUAL INSPECT AND ELEC TEST	' 8	-
728835102	'TRN B H2 RECOMBINER VISUAL INSPECT AND ELEC TEST	' 8	-
728907102	'RCP-2 13.8KV BKR OVERCURRENT PROTECTION TEST	' 4	-
728909113	'480V BKR TYPE 42 GRP 2 OVERCURRENT PROTECT TEST	' 4	-
714700101	'MANUAL REACTOR TRIP TEST	' 2	-
714910101	'RCS LEAKAGE INSPECTION	' 2	-

OPEN ITEMS

RESOLUTION NUMBER	RESPONSIBLE DEPARTMENT/ ENGINEER	NSSS OR BOP	DATE IDENTIFIED	DATE DUE	DATE RESOLVED	DESCRIPTION and STATUS
[illegible]	NSAC WENDT		12/01/87	04/22/88	/ /	DETERMINE ANY REGULATORY COMMITMENTS TO BE IMPLEMENTED
[illegible]	MAINT PHILLIPS		12/01/87	04/01/88	/ /	SCOPE OF LIVE LOAD PACKING PROGRAM IF ANY. --LIVE LOAD PACKING REQUIREMENTS ARE PENDING EVALUATION OF DCP-87144.
9	MAINT JANES		12/01/87	05/01/88	/ /	DETERMINE SCOPE OF MOVATS TESTING FOR SCHEDULE IMPACT.
14	ADMIN ABRO		12/01/87	05/01/88	/ /	DEVELOP PERSONNEL ACCESS SCREENING AND TRAINING PROGRAM & SCHEDULE
[illegible]	MAINT PHILLIPS		12/01/87	05/01/88	/ /	DETERMINE ANY MOCK-UP TRAINING REQUIREMENTS.
25	MAINT PHILLIPS	N	12/01/87	05/01/88	/ /	DETERMINE UNDERWATER INSPECTION REQUIREMENTS, ISSUE MATL. REQ. DIVER SERV.
[illegible]	ENGINEER WILLIAMS		12/01/87	04/15/88	/ /	CONTROL ROD WEAR INSPECTION. 93400C TO PRB AFTER FUEL INT. PROC.
[illegible]	MATERIALS LUNGSFORD		12/01/87	05/01/88	/ /	MATERIAL RESERVATION, STAGING, LOCATION
70	SECURITY TIMMONS		12/01/87	05/01/88	/ /	ESTABLISH INTERIM ACCESS PROGRAM. AWAITING PROCEDURE SIGN-OFF (90006-C)

RESOLUTION NUMBER	RESPONSIBLE DEPARTMENT/ ENGINEER	NSSS OR BOP	DATE IDENTIFIED	DATE DUE	DATE RESOLVED	DESCRIPTION AND STATUS
[illegible]	OSP [illegible]		01/21/88	05/01/88		IDENTIFY CTMT POLAR CRANE TO SUPPORT WORK ACTIVITIES OR EQUIPMENT TRANSFER.
[illegible]	OSP LAMKIN	N	01/21/88	05/01/88	/ /	IDENTIFY LAYDOWN AREAS ON CTMT OPER. DECK TO SUP. REACTOR DISASSEMBLY. [illegible]
40	ENGINEER [illegible]		01/[illegible]/88	04/15/88	/ /	RESOLVE CTMT SPRAY MINI FLOW CONCERNS WITH REDUCED FLOW. UNIT 2 HAS INC. DESIGN CHANGE TO REPAIR EXISTING VALVES WITH LOWER CV
46	OSP C. MONCUS		02/01/88	05/01/88	/ /	IDENTIFY ADEQUATE POWER SUPPLY FOR BREATHING AIR COMPRESSOR IN CONTAINMENT. ENGINEERING TO EVALUATE UTILIZING MCC AS POWER SOURCE.
	OSP D'AMICO		02/01/88	05/01/88		CONTINGENCY FRAGNET PREPARATION - EVALUATE IMPACT ON SCHEDULE
[illegible]0	OPERATIONS [illegible]	N	02/[illegible]/88	05/01/88	/ /	COMPLETE OPS PREPARATION FOR OUTAGE USING SIMULATOR TO SHARPEN SKILLS ON PLANT EVOLUTIONS UNIQUE TO OUTAGE (INPO RECOMMENDATION)
[illegible]1	OMT D'AMICO		02/26/88	05/01/88	/ /	DETERMINE OUTAGE SHIFT SCHEDULE I.E. 3-8'S, 2-10'S, 2-12'S. THIS ACTIVITY REQUIRED TO MANLOAD AND RESOURCE CONSTRAIN OUTAGE SCHEDULE
[illegible]4	HP [illegible]DOHERY		02/26/88	05/01/88	/ /	INVESTIGATE POSSIBLITY OF INCREASING RWP SIGN-IN LINES FOR : GENERAL RWP'S SPECIFIC RWP'S AND PROBLEM AREA RWP'S TO REDUCE CONGESTION
[illegible]7	ENGINEER CAUDILL		03/01/88	04/16/88	/ /	IS THERE A NEED TO REDO TGV (SNUBBER REDUC.) FOR NEW DATA AND ANALYSIS? YES, ADDITIONAL ANALYSIS WILL BE REQUIRED. IT HAS BEEN DETERMINED THAT LANYARD TRANSDUCERS WILL NOT BE USED. GUIDELINES FROM R.KIES DUE 04/16/88.

RESOLUTION ITEM TRACKING

DATE: 04/12/88

OPEN ITEMS

RESOLUTION NUMBER	RESPONSIBLE DEPARTMENT ENGINEER	NSSS OR BOP	DATE IDENTIFIED	DATE DUE	DATE RESOLVED	DESCRIPTION AND STATUS
69	HP YOCHERY	N	03/17/88	05/17/88	/ /	HEALTH PHYSICS TO PROVIDE ENGINEERING CURRENT PLAN ON LEAD SHIELDING. ENGINEERING TO PROVIDE EVALUATION. SPECIFIC EVALUATION WILL REQUIRE HP REVIEW AND TEMP MOD TO ENGINEERING.
70	HP BIRON	N	03/17/88	04/15/88	/ /	INITIATE RER THAT WOULD PROVIDE FOR TECH SPEC CHANGE THAT WOULD ALLOW DEMIN VALVE 1418-U8-005 OPEN DURING MODE 3/4 TO SUPPORT DECON.
71	MAINT PHILLIPS		03/17/88	05/01/88	/ /	MAINTENANCE TO DEVELOP A DETAILED PLAN ON SNUBBER TESTING. WHAT TYPE OF VENDOR SUPPORT IS REQ'D ? WHAT TYPE OF TEST EQUIPMENT REQ'D ? LOCATION ?
72	OPS KITCHENS		03/17/88	05/01/88	/ /	OPERATIONS HAS RESPONSIBLITY TO APPOINT A RETURN TO SERVICE COORDINATOR.
[illegible]	O&P D'AMICO		04/01/88	05/01/88	/ /	ORGANIZE AND ADMINISTER SOME FAMILIARIZATION TRAINING ON P/2 FOR SUPERVI-SORS AND FOREMEN. TRAIN THEM ON HOW TO READ P/2 SCHEDULES AND P/2 REPORTS.
78	ENGINEER LIDE	N	04/08/88	04/22/88	/ /	DETERMINE TURBINE BUILDING BRIDGE CRANE RESTRICTIONS.
79	ENGINEER		04/08/88	/ /	/ /	IDENTIFY SPECIFIC PENETRATION SEALING & CORE DRILL REQUIREMENTS ASSOCIATED WITH AMSAC AND THE CORRESPONDING INTERFACE WITH CONTROL ROOM WALL HVAC.

REFUELING OUTAGE MEETING
AGENDA FOR APRIL 28, 1988
OUTAGE WAR ROOM

1. OPENING REMARKS
2. SNUBBER REDUCTION - TOM ARLOTTO
3. BREATHING AIR - MARK BIRON/JOHN AUFDENKAMPE
4. LEAD SHIELDING UPDATE - JOHN AUFDENKAMPE
5. OUTAGE WORKING HOURS - JOE D'AMICO
6. TURBINE BUILDING WASHDOWN FOLLOW-UP - DUSTY RHODES
7. CONTAINMENT COATINGS - JOHN AUFDENKAMPE
8. PIPING CLEANLINESS - JOHN QUALIZZA/RIC BLAINE
9. RESOLUTION ITEM LIST
10. OPEN DISCUSSION

VOID

VOID

Procedure Review Request Form (PRRF)

(1) No. 49006-C Current Rev. 0 New Rev. 0

Title Health Physics and Chemistry Department Outage Activities

(X) New ( ) Revision ( ) Deletion ( ) Biennial Review

Reason for change New Procedure Change Required ( ) Y ( ) N

Originator ____________________ (Signature) 4/29/88 (Date)

(2) All Identified Commitments included or resolved: (✓) Y ( ) N

Quality Review performed by: R C Hand (Signature) 4.29.88 (Date)

(3) PRB review required (Table 2 or Safety Evaluation) ( ) Y (✓) N

Safety Evaluation attached: (✓) Y ( ) N

Environmental Evaluation Performed: (✓) Y ( ) N

Environmental Evaluation Attached: (✓) Y ( ) N

(4) Responsible Department Head Approval Art ____ (Signature) 2 JUN 88 (Date)

(5) PRB Meeting No. N/A

Recommend: ( ) Approval ( ) Approval w/comment ( ) Rejection Date N/A

This procedure does/does not contain an Unreviewed Safety Question.

PRB Chairman N/A (Signature) N/A (Date)

(6) PRB comments resolved and procedure changes do not impact Commitment Tracking or Safety Evaluation reviews.

Responsible Department Head Approval N/A (Signature) N/A (Date)

(7) Disposition: ( ) Approved ( ) Rejected

Reason for Rejection: ____________________

Approving Manager ____________________ (Signature) ________ (Date)

FIGURE 1

ENVIRONMENTAL EVALUATION

Document ID: 49006-C

Revision No.: 0

1. Could implementation of this document pose adverse environmental effects of any type either directly or indirectly? (Unit 1 Operating License, Appendix B) Check a or b

[ ] a. Possibly. (Explain): ____________________

[X] b. No. The nature of this document is such that it will not result in a condition which significantly alters the impact of the station on the environment.

Evaluator RCHand Date 4-29-88

Supervisor NA Date NA
(Signature required if 1a is checked)

2. If an environmental question is posed (item 1a is checked) the document will not be approved until evaluated. Forward the package to the Chemistry Department for an environmental review.

3. Attach completed environmental review and return to the evaluator (item 1) for continued processing.

FIGURE 2

SAFETY EVALUATION

Document ID No. 49006-C SHEET 1 of__

SECTION 1.0 Rev. 0

1.1 Description of proposed change, test, or experiment:
New procedure on outage activities

1.2 Reason for proposed change, test, or experiment:
Needed one procedure to road map our course during outages

1.3 Does the proposed change involve a change to Technical Specifications? Yes___ No X
Explanation: No change to tech specs is involved because this level of detail is not in Tech Specs

1.4 Does the proposed change involve a change in the facility as described in the FSAR? Yes___ No X
Explanation: No change in facility is involved This is just a roadmap procedure

1.5 Does the proposed change involve a change in procedures as described in the FSAR? Yes___ No X
Explanation: No change in procedures, this just road maps how outages should be handled

1.6 Does the proposed change involve a test or experiment not described in the FSAR? Yes___ No X
Explanation: No test or experiments are involved

Evaluator RC Hart Date 4-29-88

Supervisor [signature] Date 7 JUNE 88

FIGURE 1