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REGION II
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ATLANTA, GEORGIA 30323

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Licensee: Georgia Power Company
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Facility Name: Vogtle Electric Generating Plant, Units 1 and 2

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TABLE OF CONTENTS

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 respor . 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 cou' ' 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 changes 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 Control Room Observations

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 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 1154 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 verified 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
- 14220-1, 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