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Exhibit 83, page 1 of 17.

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NUCLEAR REGULATORY COMMISSION
Docket No. 50-424/425-OLA-3 EXHIBIT NO. II-83
In the matter of Georgia Power Co. et al., Vogtle Units 1 & 2
☐ Staff ☐ Applicant ☑ Intervenor ☐ Other
☑ Identified ☑ Received ☐ Rejected Reporter SD
Date 9/28/95 Witness REYES/ZIMMERMAN

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: VOGTLE SPECIAL TEAM INSPECTION REPORT NOS. 50-424,425/90-19
SUPPLEMENT 1

This refers to the inspection conducted by a Special Inspection Team on August 6 through 17, 1990. Previous correspondence associated with this inspection was transmitted to you on January 11, 1991. As discussed in the Inspection Summary of that document, the results of the allegation followup team would be the subject of separate correspondence. This report includes, in part, the results of that followup team. The inspection included a review of activities authorized for your Vogtle facility. At the conclusion of the inspection, these 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.

The inspection teams' review of the allegations identified several additional weaknesses in operational polices and practices. These are identified in the inspection summary of the enclosed inspection report.

The inspection findings indicate that certain activities appeared to violate NRC requirements. The apparent violation associated with failure to provide accurate information to the NRC during the inspection is under consideration for escalated enforcement action. Accordingly, a Notice of Violation for this issue is not being issued at this time, and a response to this subject is not required. However, please be advised that the number and characterization of violations described in the enclosed Inspection Report associated with this subject may change as a result of further NRC review. You will be advised by separate correspondence of the results of our deliberations on this matter. We will contact you at a later date to arrange an enforcement conference to discuss this issue.

The additional violation described in this report, references to pertinent requirements, and elements to be included in your response are described in the Notice of Violation.

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.

In accordance with 10 CFR 2.790(a), 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,

Ellis W. Merschoff, Acting Director
Division of Reactor Projects

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

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ENCLOSURE 1

NOTICE OF VIOLATION

Georgia Power Company
Vogtle 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, a violation of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C (1990), the violation is listed below.

Technical Specification 6.7.1.a requires that written procedures be established or implemented for those activities delineated in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978.

Contrary to the above, during the inspection conducted on August 6-17, 1990, two examples were identified in which the licensee failed to establish or implement the procedures for these required activities as follows:

1. Administrative Procedure 00150-C, "Deficiency Control," states that a deficiency card must be written if the deficiency involves safety-related components which are to be dispositioned "use-as-is/repair," or other conditions involving safety-related components which require engineering support or other technical assistance to determine if the component is deficient.

   On August 17, 1990, the NRC identified that a deficiency card was not written on residual heat removal (RHR) pump #1B (a safety-related component) to document the pump's degraded conditions which were dispositioned "use-as-is". (Discussed in Section 2.2 of this inspection report)

2. Administrative Procedure 00100-C, "Quality Assurance Records Administration," Paragraph 4.1.1.8, specifies that quality assurance (QA) records will exhibit necessary and appropriate signatures or initials and dates.

   On August 17, 1990, the NRC identified that the Unit Superintendent incorrectly initialed, dated, and signed a QA record which voided Temporary Change Procedure (TCP) 1802-C-7-90-1 to Abnormal Operating Procedure 18028-C, "Loss of Instrument Air," with the date of June 12, 1990, in lieu of the actual date (June 15, 1990) on which the document was signed. (Discussed in Section 2.3 of this inspection report)

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

Georgia Power Company
Vogtle Units 1 and 2

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

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. 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

Ellis W. Merschoff, Acting Director
Division of Reactor Projects

Dated at Atlanta, Georgia
this 01 day of Nov. 1991

ENCLOSURE 2

Report Nos.: 50-424,425/90-19, Supplement 1

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 Leader: Chris A. VanDenburgh, Section Chief, Division of Reactor Inspections and Safeguards, Office of Nuclear Reactor Regulation

Team Members:
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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
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Peter A. Taylor - Reactor Inspector, DRS, Region II
McKenzie Thomas - Reactor Inspector, DRS, Region II
John D. Wilcox, Jr. - Operations Engineer, NRR

Submitted by: Pierce H. Skinner — Oct. 7, 1991
Pierce H. Skinner, Section Chief 3B — Date Signed
Region II, Division of Reactor Projects

Approved by: Alan R Herdt — Oct 7, 1991
A. R. Herdt, Chief, Branch 3 — Date Signed
Region II, Division of Reactor Projects

TABLE OF CONTENTS

INSPECTION SUMMARY

Activities which occurred in early 1990 at the Vogtle Electric Generating Plant (VEGP) 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 and conservative manner. To address these concerns, the NRC performed a special team inspection to determine if the licensee operated the facility in accordance with approved procedures and within the requirements and intent 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 aggregation of the facts and circumstances associated with the operational events and the allegations was viewed as a possible indicator of a non-conservative attitude on the part of the facility's operating staff. This 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 the allegations and their impact on the safe and conservative 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 and conservative manner in accordance with the facility's operating license.

The allegations followup team verified the technical validity and safety significance 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 investigation into the intent of the alleged violations. NRC investigations may be implemented to further review these issues.

The inspection substantiated the occurrence of some of the specific events described in the allegations. However, most of the allegations were not substantiated. These events resulted in one violation (50-424,425/90-19-13) and one apparent violation (50-424,425/90-19-12) of regulatory requirements as discussed in part in this inspection report supplement and two violations that were identified in the initial part of this inspection report (50-424, 425/90-19-01 and 50-424.425/90-19-02). In addition, two events were previously identified as non-cited violations (50-424/90-10-03 and 50-425/90-01-01).

The operations followup team identified several occasions where responsible managers and supervisors verbally supplied inaccurate information to the inspection team during the inspection.

Additional observations and conclusions of the inspection team are detailed in NRC Inspection Report 50-424,425/90-19 issued January 11, 1991. The bases for these previous conclusions are summarized below.

Operational Policies and Practices

NRC Inspection Report 50-424,425/90-19 identified several examples in which the licensee's operational policies and practices had the potential to adversely affect the operation of the facility. The allegation followup team's review of the allegations identified the following additional examples in which the licensee's operational policies and practices had the potential to adversely affect the safe operation of the facility:

1) The licensee's method of conducting Plant Review Board (PRB) meetings had the potential for adversely affecting open discussions among the PRB members. This concern was based on an example in which a PRB voting member felt intimidated and feared retribution during a PRB meeting because of the presence of the general manager and the absence of dissenting opinions in the PRB meeting minutes. Continued licensee action is necessary to ensure that PRB members freely and openly express their technical opinions and safety concerns. (Section 2.7)

2) The licensee's practice of signing and dating quality assurance records was controlled by administrative procedures; however, there was a confirmed example in which a signature was backdated to reflect the actual date of performance. The backdating issue was verified and is identified as an example of Violation 50-424,425/90-19-13: "Failure to Establish or Implement Procedures for Required Activities." (Section 2.3)

3) The licensee's practice of not initiating a deficiency card (DC) during troubleshooting activities involving the questioned operability of the residual heat removal (RHR) pump prevented a documented engineering evaluation for either the nuclear service cooling water (NSCW) outlet leak or the excessive vibration on the RHR pump motor. The failure to implement this administrative procedure was identified as an example of Violation 50-424,425/90-19-13: "Failure to Establish or Implement Procedures for Required Activities." (Section 2.2)

4) The licensee's method of appraising the performance of the licensed operators resulted in a potential disincentive for identifying items which may result in LERs or violations. (Section 2.8)

Accuracy of Information

The inspection concluded that during the inspection inaccurate information was received on several occasions, from responsible managers and operators on topics well within the scope of their specific responsibility. In four instances the initial information supplied was clearly incorrect or inadequately researched. The inspection team concluded that in each of these examples, licensee officials provided inaccurate, unsworn, oral statements concerning information which concerned topics well within their responsibilities.

In two cases, the inaccurate information was clearly significant to the inspection process. Specifically, (1) if the containment isolation valves received an automatic closure signal, the valves could remain open without a violation of TS 3.6.3, and (2) if the snubber modifications had been performed in conjunction with other preplanned preventive and corrective maintenance, then the voluntary entries into LCO 3.7.8 would not have been required. The inspection team identified that the failure to provide accurate information is a violation of the requirements of 10 CFR 50.9 concerning accuracy and completeness of information. This is identified as an apparent Violation 50-424, 425/90-19-12: "Failure to Provide Accurate Information to the NRC as Required by 10 CFR 50.9", as noted by the following examples:

1) Containment Isolation Valves: During a Unit 1 surveillance procedure, the unit shift supervisor (USS) stated, and the operations manager later confirmed, that the containment isolation valves for the hydrogen monitor system were allowed to be opened without entering the LCO action requirements for TS 3.6.3 because the valves received an automatic isolation signal. The inspection identified that these containment isolation valves were remotely-operated, manual valves without automatic isolation signals. (Discussed in Section 2.2.1.1 of Inspection Report 50-424,425/90-19 issued January 11, 1991).

2) Snubber Reduction: The operations manager stated that, after Unit 1 refueling outage 1R2, the modifications to the snubbers were done in conjunction with preplanned system outages which were required for other preventive or corrective maintenance or testing. The inspection identified that few of the snubber modifications were done jointly with pre-planned system outages. (Discussed in Section 2.1.1.4 of Inspection Report 50-424,425/90-19 issued January 11, 1991).

3) Personnel Accountability: The operations manager stated that the shift superintendents (SS) reported directly to the operations manager and that he personally prepared their performance appraisals. The inspection

revealed that the SS reported to the unit superintendent (US), and that the US personally prepared the performance appraisals of the SS. (Discussed in Section 2.1 of this inspection report)

4. TS 3.0.3 Actions: The Unit Superintendent indicated that there were no Operations Department actions which were anticipated or required within the first three hours of entering the action statement of TS 3.0.3. The inspection identified that the VEGP management policy and statement practice required preparations for a power reduction, including informing the load dispatcher within the first hour. (Discussed in Section 2.1.1.3 of Inspection Report 50-424,425/90-19 dated January 11, 1991).

In summary, this supplement of the inspection identified one violation, one apparent violation, and two inspector followup items. The violations include: (1) a violation of TS 6.7.1.a in that, two examples were identified of the licensee failing to implement actions in accordance with administrative procedures and (2) the apparent violation of 10 CFR 50.9 which relate to four examples in which responsible licensee officials provided inaccurate information to the NRC during the inspection.

The two inspector followup items include: (1) an unreviewed safety question concerning the use of the alternate radwaste building, and (2) the lack of operator guidance concerning the applicable limiting conditions of operation during engineered safety features actuation system sequencer outages.

INSPECTION DETAILS

1.0 INSPECTION OBJECTIVES

Recent activities which have occurred at VEGP have raised concerns within the NRC as to the ability and the determination of the licensee to operate the facility in a safe and conservative 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 aggregation of the facts and circumstances associated with the operational events and the allegations was viewed as a possible indicator of a non-conservative attitude on the part of the facility's operating staff which warranted the immediate initiation of special inspection activities.

Because a non-conservative attitude or operating philosophy may represent a hazard to the health and safety of the public, 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 allegations on the safe operation of the facility. The purpose of the inspection was to determine if the licensee operates the facility in a conservative and 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, and

2) Determine the technical validity and safety significance of each of the allegations and their impact on the safe and conservative 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 and conservative manner in accordance with the facility's operating license.

The specific inspection activities of the operations team was described in Inspection Report 50-424,425/90-19 issued January 11, 1991. The efforts and conclusions of the allegations followup team are described in this supplement to that inspection report. In addition, this supplement identifies several violations and potential weaknesses in the licensee's operational polices and practices. Specific details are contained in the sections that follow and in the Inspection Summary.

2.0 ALLEGATION FOLLOWUP

The inspection team reviewed several allegations for their technical validity and interviewed licensed and non-licensed personnel to determine their personal knowledge and experience regarding these issues. This portion of the inspection was performed to determine the validity and significance of the allegations.

The inspection of the allegations included technical reviews of the licensee's records, logs, and interviews of the personnel involved in the alleged violations. Although a transcribed record was not required for every discussion with the licensee's staff, the inspection team conducted sworn, transcribed interviews with selected individuals in order to document (1) the individual's personal knowledge and involvement in the alleged violations and (2) the circumstances and rationale for their individual actions. Although an OI investigator was assigned to the inspection team to assist during the transcribed interviews, this inspection was not an investigation into the intent of the alleged violations. The intent aspect of the alleged activities may require further NRC investigations.

The interviews were transcribed after the technical evaluations of the allegations in order to permit a focused interview and to minimize the length and scope of the transcribed proceedings. The transcribed interviewees are listed in Appendix 1 in the order in which they were conducted. The sworn testimony was a factor on which the inspection team reached its conclusion on each of the allegations. These conclusions are presented in the material that follows (Sections 2.1 through 2.8).

2.1 <u>Improper Installation of FAVA System</u>

An allegation indicated that VEGP installed and operated a radwaste microfiltration system, known as the FAVA system, without performing an adequate engineering and safety evaluation (i.e., 10 CFR 50.59). Furthermore, the material configuration, fabrication and quality of the system did not meet the guidance of Regulatory Guide (RG) 1.143 and the requirements of the American Society of Mechanical Engineer's (ASME) Code.

The FAVA system was temporarily installed for removing Niobium-95. The system was later determined to be better suited for as-low-as-reasonably-achievable considerations during refueling outage 1R2, particularly for removing Cobalt-59 and Cobalt-60. VEGP planned to replace this temporary modification with a permanent, high-quality, steel system in the future; however, the health and safety of the public may be jeopardized if a break in the system (resulting in a radioactive release to an unrestricted area) occurred in the interim.

Discussion

In February 1988, VEGP experienced difficulty in removing colloidal Niobium-95 following a reactor shutdown for maintenance work. FAVA Control Systems (FAVA) was hired to help rectify this problem. FAVA was selected because of its experience in filtration and demineralization. The situation was corrected by installing a 0.35-micron filter system downstream of the existing vendor-supplied pre-filters. However, a large volume of radwaste was generated as the 0.35-micron filters rapidly exhibited high differential pressure and were required to be changed frequently. The need to change filters frequently also resulted in additional radiation exposure to Radwaste Department personnel.

Upon evaluation of the performance of the 0.35 micron filter system, the Radwaste Department felt that the best approach to the problem was a back-flush, pre-coat filter system. However, no operational data was available for a system of this type in this specific application. FAVA supplied a proprietary Ultra Filtration System (Model No. 5FD/E) for testing purposes in order to evaluate whether or not this was a viable and economic solution to the problem. The FAVA system was installed before the Unit 1 refueling outage and was operated under Test Procedure T-OPER-8801. The test system kept liquid effluent releases well below TS limits. On the basis of an evaluation of test results by the Radwaste, Chemistry, and Engineering Departments, a general work order was initiated to purchase a permanent system.

In the early part of 1989, a Quality Assurance (QA) Department audit identified a significant audit finding involving a programmatic breakdown in the procurement of the FAVA system and the failure to meet commitments of the Final Safety Analysis Report (FSAR). Because of that finding, the FAVA system was removed from service. In late 1989, the licensee sought to reinstall the FAVA system under a temporary modification because colloidal Cobalt-59 and Cobalt-60 had to be removed. The Plant Review Board (PRB) reviewed this temporary modification and several members expressed strong objections to it based on the previous QA audit finding.

Subsequently, a request for engineering assistance (REA) was submitted and a 10 CFR 50.59 safety evaluation was performed in late 1989. This safety evaluation did not properly address the guidance of RG 1.143 regarding the use of polyvinyl chloride (PVC) piping. Therefore, another safety evaluation was performed in February 1990 to address this issue--particularly with respect to radiation degradation.

The February 1990 safety evaluation specifically stated that the FAVA system did not conform to the criteria of RG 1.143. This deviation was found to be acceptable for the following reasons:

1) The design of the FAVA system had been previously evaluated and found to be adequate in the response to REA VG-9057 dated November 28, 1989 (log SG-8592).

2) The location of the FAVA microfiltration system inside a shielded, watertight vault provided adequate assurance that any system failures will be contained and would not create the potential for offsite releases of radioactivity.

3) The presence of PVC pipe in the FAVA system, although prohibited by RG 1.143, was acceptable because the radiation exposure to the plastic was within acceptable limits for up to 6 months based on the following:

   a) The amount of PVC piping used was not extensive and was contained on the FAVA filter skid.

   b) There were no reported leaks or malfunctions during the approximately 6 months that the FAVA system filter was previously in use.

   c) Since the FAVA system filter skid was located within the demineralizer vault, it would be protected from being damaged.

   d) On the basis of the assumed length of time that the PVC piping would be used in a radioactive environment and the activity levels of the effluent at this stage in the liquid radwaste process, the integrated dose to the PVC piping would be well below the radiation damage threshold for PVC pipe as reported in Electric Power Research Institute (EPRI) Report NP-2129, dated November 1981 (i.e., 6.5 rad over a 6 month period versus the radiation damage threshold of 5.0×10^5 rad).

   e) The PVC pipe would not be subjected to excessive pressure conditions since the maximum available inlet pressure to the filter was 80 to 100 pounds per square inch gauge (psig) which is well below the maximum allowable working pressure of 120 psig for the PVC pipe.

   f) The system could be operated at design-basis conditions for 182 days before it would exceed the radiation damage threshold. However, under conditions currently existing at the plant, the expected dose to the PVC piping will be less than 0.1 percent of the design basis.

Although the testimony of one of the PRB members indicated that the temperature effects on the use of PVC in the FAVA System were not adequately evaluated before the system was installed, the testimony of the corporate system engineer indicated that this was considered prior to installation, although not specifically documented in the safety evaluation.

VEGP management subsequently consulted the NRC resident inspector to seek an NRC position with regard to placing this system back in service. Supplemental information was also provided documenting reasons why it should not be placed in service. This package was forwarded to Region II and the Office of Nuclear Reactor Regulation (NRR) for review. In March 1990, following Region II and NRR concurrence via a telephone conference, the licensee placed the FAVA system in service with the following NRC stipulations:

1) Procedures for operating the FAVA system required an operator to be in attendance for the entire length of time the system would be in operation.

2) All hoses going to and coming from the FAVA system required verification that they met the requirements of RG 1.143.

3) The cover over the FAVA system was required to be securely fastened when the system was in operation to ensure that if a spraying leak developed, it would be contained in the concrete vault.

4) The design of the walls of the alternate radwaste building (ARB) was required to be evaluated to determine whether or not a design modification should be made to reduce the potential of wall leakage in the event that a hose leak developed and sprayed its contents on the walls.

In June 1990, in response to item 4 (above), the licensee revised Part G of the safety evaluation for the FAVA system. Part G of the safety evaluation addressed the effect that operation of the FAVA system would have on the probability of occurrence or consequences of accidents described in the FSAR. Although there was no comparable accident analysis in the FSAR that addressed the ARB accidents or the consequences of accidents in the ARB, the FSAR accident analyses (Chapters 15.7.2 and 15.7.3) did describe worst-case releases of the contents of the recycle holdup tank (HUT).

The first bounding analysis in Chapter 15.7.2 addressed the release of the entire gaseous radioactive contents of the HUT to the environment at ground level and the second bounding analysis addressed the release of the entire liquid contents of the HUT through an assumed crack in the ARB floor directly into the ground water supply. In both cases, the 10 CFR Part 100 and 10 CFR Part 20 limits were not exceeded. These criteria were consistent with criteria provided in NRC Circular 80-18, "10 CFR 50.59 Safety Evaluations for Changes to Radioactive Waste Treatment System." However, neither of these analyses addressed the potential for wall spray down and leakage through the ARB walls and the subsequent release path to the environment. Therefore, the licensee revised the safety evaluation in June 1990 to address the consequences of a hose break on the FAVA system which would result in wall spray down and potential leakage to the environment.

The inspection team's review of the revised Part G of the safety evaluation identified several erroneous assumptions with respect to the release path and the dilution volumes that could be used in the analysis of a hose break and resultant wall spray down. However, the inspection team also found that the design of the FAVA system (i.e., the use of a system cover) would prevent wall spray down and that the only potential source for wall spray down and subsequent leakage was from a hose break in another radwaste system in the ARB. Therefore, the inspection team concluded that the FAVA system safety evaluation dated June 1990, adequately addressed the temporary modification for the installation of the FAVA system; however, the inspection team's review identified an unreviewed safety question concerning the release paths and consequences of a failure of the other radwaste systems in the ARB.

In addition, the team noted that in Supplements 3 and 4 of the Safety Evaluation Report (SER), the NRC staff reviewed and accepted the design of the ARB and specifically addressed the consequences of a hose break on a radwaste system in the ARB. However, the SER supplements addressed the effects of high airborne activities and puddling and did not address the potential for wall spray down and leakage. The ARB was installed before the plant was licensed; therefore, the NRC approved the design and use of the ARB in Supplements 3 and 4 of the SER. Thus, there was no requirement to perform another evaluation of the potential effects of hose breaks on systems other than the system being installed by the temporary modification (i.e., the FAVA system). Because the design of the FAVA system effectively prevented a wall spray down, this was not a concern that was required to be addressed by the FAVA system safety evaluation. Nevertheless, now that it has been identified, the consequences of a hose break and wall spray down in the other ARB radwaste systems must be resolved. Therefore, this issue will be followed as an inspector followup item pending further review and evaluation and is identified as IFI 50-424,425/90-19-14: "Potential Unreviewed Safety Question Regarding Spray Down of the Alternate Radwaste Building."

Conclusion

Although the FAVA system was originally installed without an adequate safety evaluation and did not meet the regulatory guidance, the inspection team confirmed that the subsequent safety evaluations were acceptable for the system's use.

As a result of QA Department's significant audit finding in early 1989 involving a breakdown in procurement and failure to meet FSAR commitments, the system was removed from service. Subsequently, the FAVA system was returned to service following two safety evaluations which adequately addressed the use of PVC piping with respect to radiation degradation and pipe rupture. Therefore, these safety evaluations justified the use of the FAVA system, even though the recommendations of RG 1.143 and ASME Code requirements were not met. Although the safety evaluations did not specifically address high-temperature effects, the testimony indicated that these effects had been considered before the system was installed.

Although the safety evaluation performed in June 1990 at the request of the NRC Region II Office did not adequately evaluate the effects of a wall spray down and wall leakage to an unrestricted area, this evaluation was not required because the FAVA system has a protective cover and the use of hoses and effects of hose breaks (i.e., airborne activity and puddling) were addressed in SER Supplements 3 and 4.

Regardless of whether the safety evaluation was required to address the effects of a break in the hoses (which could result in wall spray down or leakage), the inspection team identified a new concern involving the use of the ARB because the safety evaluation inadequately addressed the potential effects of wall spray down from any other source in the ARB owing to erroneous assumptions concerning the release path and the dilution volumes. This issue associated with the potential effects of wall spray down in the ARB should be reviewed by the licensee under 10CFR50.59 requirements.

2.2 Operability of the Residual Heat Removal Pump

An allegation indicated that during Unit 1 refueling outage 1R2 with residual heat removal (RHR) Train A out of service for maintenance, the Train B RHR pump experienced excessive vibration and a nuclear service cooling water (NSCW) motor cooler outlet leak. In addition, TS 3.9.8.1, "RHR and Coolant Circulation," was allegedly violated because the Operations Department chose not to declare RHR pump 1B inoperable in an effort to mitigate the impact on the critical work path.

Discussion

TS 3.9.8.1 requires at least one RHR train to be operable and in operation during Mode 6 (refueling) when the water level above the top of the reactor vessel flange is greater than or equal to 23 feet or more. Otherwise,

> Suspend all operations involving an increase in the reactor decay heat load or a reduction in boron concentration of the reactor coolant system and immediately initiate corrective action to return the required RHR train to operable and operating status as soon as possible and close all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere within 4 hours.

The inspection team verified that during Unit 1 refueling outage 1R2 with higher than normal vibration measurements on the RHR pump 1B and a leak on the NSCW outlet of the RHR motor cooler, Operations Department personnel did not declare the pump inoperable. This determination was made after consulting with the on-shift duty engineer from the Engineering Department and was based on the determination that the pump would fulfill its intended safety function in Mode 6. Specifically, the RHR pump was capable of removing decay heat from the partially defueled reactor core.

The testimony of the individuals involved indicated that this operability determination was based on the fact that the vibration readings taken at the inservice test (IST) surveillance points did not reach the IST Alert levels and were therefore acceptable for continued service. Although the high vibration readings on the top end of the RHR pump were later determined by the vendor (Westinghouse) to be excessive, at the time of the operability evaluation, the licensee accepted these values, regardless of their magnitude, because the readings at IST test points were below the Alert levels. The testimony also indicated that, even with a leak on the NSCW outlet of the RHR motor cooler, the motor was receiving full cooling water flow and cooling would not have been immediately compromised following a complete NSCW discharge pipe break.

Furthermore, the testimony indicated that the Operations Department had implemented compensatory actions to monitor the vibration levels and NSCW leakage and ensure the continued operability of the pump by stationing an operator at the RHR pump to monitor the vibration levels and notify the control room if the vibration levels increased, thus allowing the control room to implement the actions of the Limiting Conditions for Operation (LCO).

The inspection team also noted that in event of a catastrophic failure of the RHR pump, all the required actions of TS 3.9.8.1 (i.e., closing all containment penetrations) could have been completed within the required 4 hour time period of the LCO because the LCO for TS 3.9.4, "Containment Building Penetrations," was in effect during this time period. This LCO was implemented due to the movement of irradiated fuel from the core to the spent fuel pool. The LCO required that,

> The equipment door be closed and held in place by at least four bolts; at least one door in each airlock be closed; and each penetration providing direct access from the containment atmosphere to the outside atmosphere shall be either closed by an isolation valve, blind flange, or manual valve, or be capable of being closed by an operable automatic containment ventilation isolation valve.

As a result of the implementation of TS 3.9.4, the only remaining action for the LCO of TS 3.9.8.1 would have been to close the containment purge valve which receives an automatic closure signal and could have been isolated within the LCO action times.

During the course of this review, the inspection team found that the licensee failed to initiate a deficiency card for either the NSCW leak or the excessive vibration as required by Operations Procedure 00150-C, "Deficiency Control." This procedure requires that a deficiency card be written if the deficiency involves safety-related components which are to be dispositioned "use-as-is/repair," or other conditions involving safety-related components which require engineering support or other technical assistance to determine if the component is deficient. Failure to establish, implement, and maintain adequate operating procedures represents a violation of TS 6.7.1.a. This item is identified as an example of Violation 50-424/90-19-13: "Failure To Establish or Implement Procedures for Required Activities."

Conclusion

The inspection team confirmed that the Operations Department had an adequate engineering basis for accepting the operability of the RHR pump in spite of the pump's deficiencies. In addition, the team concluded that declaring the pump inoperable would not have impacted the critical work path: the LCO actions would not have been restrictive because containment (excluding ventilation) had been isolated as required by TS 3.9.4. The LCO actions would not have prevented the continuation of refueling activities because the actions to close all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere would only have required closing the containment purge valve which has an automatic closure signal.

In addition, the inspection team identified that the licensee violated the station's administrative procedures by failing to initiate a deficiency card for either the NSCW outlet leak or the excessive vibration on the RHR motor as required by Operations Procedure 00150-C.

2.3 Backdating of Signatures

An allegation indicated that a temporary change to Abnormal Operating Procedure (AOP) 18028-C, "Loss of Instrument Air," was not approved within the 14-day requirement of TS 6.7.3.c; and that the unit superintendent intentionally incorrectly signed and dated the temporary change to indicate that the TS requirement was satisfied.

Discussion

TS 6.7.3.c requires that temporary changes to AOPs which do not involve changes to the intent of the original procedure be documented and reviewed in accordance with TS 6.7.2 and approved within 14 days of implementation. TS 6.7.2 requires that changes to AOPs be reviewed as stated in administrative procedures and approved by the PRB and general manager. Administrative Procedure 00100-C, "Quality Assurance Records Administration," Paragraphs 4.1.1.4 and 4.1.1.8, require that corrections to Quality Assurance records exhibit necessary and appropriate signatures, initials, and dates.

Operations Procedure 18028-C, Revision 7, provided operator actions in the event of a loss of the instrument air system. A temporary change to the procedure was initiated on May 29, 1990, to delete the references to the header isolation at 70 psig and the associated actions. This change was processed in accordance with Administrative Procedure 00052-C, "Temporary Changes to Procedures," which allowed the temporary implementation of minor changes to procedures as long as the change was approved by the PRB and signed by the general manager within 14 days of the temporary change. Therefore, Temporary Change Procedure (TCP) 1802-C-7-90-1 was required to be approved by the PRB and signed by the general manager by June 12, 1990.

The PRB tabled the TCP on June 8, 1990, (PRB meeting 90-81) and assigned action to the Operation's Department to void the TCP or revise the TCP to incorporate the PRB comments. Revision 8 to Operations Procedure 18028-C was developed to modify valve numbers and descriptions reflected in Temporary Modifications 1-90-006 and 2-90-002. This revision superseded the changes of the TCP. On June 12, 1990, the PRB approved Revision 8 (PRB meeting 90-82) and the TCP was removed from the control room copies of the procedure. On June 15, 1990, the unit superintendent lined out the operations manager's previous approval of the TCP and marked the TCP form as disapproved by the Operations Department. The date entered on the form was June 12, 1990.

On June 22, 1990, the PRB secretary initiated DC 1-90-282 which indicated that the unit superintendent incorrectly dated the TCP with the date of June 12, 1990, rather than the actual date of June 15, 1990, and DC 1-90-283 which indicated that the TCP was not processed within the required 14 days (i.e., by June 12, 1990). The resolution of these DCs, the associated PRB meeting minutes, and discussions with the operations manager and Nuclear Safety and Compliance Department staff indicated that described deficiencies were acknowledged and confirmed by the Operations Department on July 3, 1990, and attributed to personnel error. The TCP form was dated with the date on which the Operations Department decided to void the TCP and not the date on which the original was actually signed.

As part of the corrective actions for DC 1-90-282, a TCP record correction notice was initiated to correctly indicate the date on which the TCP form was processed; however, the TCP record correction notice could not be produced--one was subsequently written on August 14, 1990. In addition, the operations manager counselled the unit superintendent and assigned him to investigate both DCs because he was the most knowledgeable of the deficiencies and the assignment served to reinforce the reprimand. The subsequent PRB meeting of June 28, 1990, (PRB meeting 90-90) determined that the 14-day TS violation addressed in DC 1-90-283 was reportable to the VEGP vice president, but not to the NRC. However, the inspection team found that the report to the VEGP vice president was not made. On August 9, 1990, the PRB (PRB meeting 90-104) confirmed that the report was required. As of August 17, 1990, the licensee had not issued the required report to the VEGP vice president; however, the licensee intended to issue the report.

With respect to the rationale for the unit superintendent's actions, the inspection team learned (during discussions with the Technical Support Manager) that the PRB secretary told the unit superintendent on June 15, 1990, that the TCP needed to be voided and a DC written for violating the 14-day requirement of TS 6.7.3. As discussed in Section 2.8 of this inspection report, Operations Department personnel are held personally accountable for violations and LERs (i.e., there is a direct impact on their bonus pay) therefore, a reportable occurrence based on this event could have adversely impacted the unit superintendent's salary.

The testimony of the unit superintendent indicated that he dated the TCP with the date (June 12, 1990) on which the PRB disapproved it and not the date on which it was actually signed (June 15, 1990). Additionally, the unit superintendent had no recollection of any discussions on June 15, 1990, regarding violation of the 14-day TS requirement. He indicated that he never considered the 14-day requirement despite his previous knowledge and training concerning this requirement and the June 12, 1990, expiration date indicated on the TCP form.

The testimony of the PRB secretary indicated that during a discussion with the unit superintendent on June 15, 1990, she identified the need to void the TCP, as well as the need to write a DC for violating the 14-day TS requirement.

Therefore, the inspection team was concerned about whether the TCP was voided before or after the PRB secretary identified the need to void the TCP and initiate a DC. In order to resolve this discrepancy, the inspection team discussed the discrepancy with the PRB secretary on August 16, 1990. In addition to earlier testimony, the PRB secretary indicated that during her discussions concerning the TCP with the unit superintendent on June 15, 1990, the unit superintendent had indicated that the TCP had already been voided earlier in the day.

Conclusion

On the basis of the statements of the US that he had dated the TCP based on the PRB disapproval date and not the date which he signed it, the inspection team concluded that backdating to avoid a violation of the 14-day TS requirement was not substantiated. In addition, the concern that this practice was a plant-wide problem was not substantiated. However, the inspection team did confirm that TCP 1802-C-7-90-1 had been dated incorrectly; this is a violation of Administrative Procedure 00100-C, "Quality Assurance Records Administration," Paragraphs 4.1.1.4 and 4.1.1.8 and will be identified as an example of Violation 50-424,425/90-19-13: "Failure to Establish or Implement Procedures for Required Activities."

2.4 Reportability of Previous Engineered Safety Features Actuation System (ESFAS) Load Sequencer Outages

An allegation indicated that the Operations Department incorrectly used a 72-hour shutdown requirement when one of the two ESFAS load sequencers was previously inoperable. It was also indicated that VEGP had taken no action to ensure that the past occurrences were identified and reported to the NRC as required by 10 CFR 50.73, despite newly acquired information that deenergizing an ESFAS sequencer required entry into the 1 hour LCO action requirements of TS 3.0.3. In addition, the possibility existed that the LCO for TS 3.0.3. (i.e., 7 hours to hot standby) were exceeded when the sequencers were previously deenergized for maintenance and testing. This concern was based on (1) the lack of a specific TS for the sequencers, (2) the Operations Department historically linking the sequencer outages to the emergency diesel generator (EDG) LCO of TS 3.8.1.1.b (78 hours to hot standby), (3) a limited review of past maintenance work orders (MWOs) indicated possible sequencer deenergization; and (4) comments by the engineering staff that the sequencers had been previously deenergized.

Discussion

There are two ESFAS sequencers for each unit--one for each 4.16-kilovolt (kV) emergency bus. Each sequencer is activated by one of two conditions, undervoltage (UV) on the associated emergency bus or a respective train's safety injection (SI) signal. Upon receipt of either or both of the initiating signals, each sequencer will perform all or part of the following functions:

- Start the associated EDG
- Stop any test sequence in progress

- Close the associated EDG breaker (UV only)

- Energize the associated train's engineered safety features (ESF) loads as determined by the initiating signal.

Each ESFAS sequencer contains three levels of UV detection and system response, as well as the power supply for this UV circuitry. Four potential transformers monitor the emergency bus voltage for these three levels of degraded bus voltage (Level 1, ≤ 70 percent; Level 2, ≤ 86 percent; and Level 3, ≤ 88.5 percent) and furnish an analog signal to three sets of four bistables located in one of the five sequencer cabinets.

Level 1 is the "loss of voltage" and Level 2 is the "degraded voltage" which is referred to in TS Table 3.3-2, Items 6.d, 8.a, and 8.b. As these TS items (applicable in Modes 1 through 4) do not address the loss of all four channels in Level 1 or in Level 2 (as would be the case when the sequencer is deenergized), TS 3.0.3 would apply if such a loss were to occur. It should be noted, however, that if the sequencer were deenergized, it could not respond to a safety injection signal either. Therefore, there would be only one automatic safety injection actuation channel (i.e., associated with the unit's unaffected sequencer) and Item 1.b of TS Table 3.3-2 (6 hours to hot standby) would be the most limiting LCO.

Discussions with the operations manager, the assistant general manager-plant support, and system engineers for the ESFAS and sequencers confirmed that the Operations Department historically linked the sequencer outages to the EDG LCO of TS 3.8.1.1.b (78 hours to hot standby). Although the applicability of TS Table 3.3-2 and TS 3.0.3 to sequencer outages had been recently identified, past sequencer outages were not reviewed. Therefore, with the assistance of the licensee, the inspection team reviewed the completed MWOs which were performed on the sequencers on Units 1 and 2, as well as the related Instrumentation and Control (I&C), Engineering, and Operations Department surveillance tests.

The review of completed MWOs did identify several instances where the work performed would most likely require the sequencers to be deenergized; however, the associated unit was found to have not been in Modes 1, 2, 3, or 4 at the time the work was performed. Somewhat related to this concern, the review did identify two occurrences (March 4 and June 17, 1987) where the Unit 1 Train B sequencer was inoperable during the change of sequencer controller card A (SLOT A4-3). Specifically, when the controller card was removed, both the automatic SI function and UV function for the sequencer were rendered inoperable. Because the unit was in Mode 3 (hot standby) during these two occurrences, the sequencers and the ESFAS were required to be operable per TS 3.3.2. However, the associated LCO status sheets (1-87-356, dated March 4, 1987 and 1-87-566, dated June 17, 1987) only recognized TS LCO 3.8.1.1.b as being applicable to the outage. Despite the fact that LCOs associated with TS Table 3.3-2 (Item 1.b) and TS 3.0.3 were not recognized, these TS were not violated since the system was restored within 30 minutes and 10 minutes, respectively.

Similar to the MWO review, the inspection team's review of related I&C, Engineering, and Operations Department's surveillance tests did not find any examples of the sequencers or the ESFAS being deenergized in Modes 1 through 4. Completed 18-month ESFAS channel calibrations, EDG tests, and ESFAS tests were verified as having been done in Modes 5 and 6. Completed quarterly testing of the ESFAS Auto SI K610 slave relay, which removed the automatic SI signal to the sequencer, were verified to be performed within time limits allowed by TS 3.3.2. All other sequencer testing that used installed test circuitry is automatically bypassed on an SI or UV signal.

In addition to the inspection team's review of MWOs and surveillance test procedures, the system engineers for the sequencers and ESFAS [as well as the nuclear steam supply system (NSSS) supervisor] were asked if they knew of any time in which the sequencers were deenergized in Modes 1 through 4. None of these engineers remembered any such occurrences.

A review of applicable operator training material (System Description 8b for Engineered Safety Features System Sequencers) revealed that there was no reference to ESFAS TS 3.3.2, just those for the diesel and other power sources and distributions (i.e., TS 3.8.1.1, TS 3.8.3.2, TS 3.8.2.1, TS 3.8.3.1, and TS 3.8.3.2.). This finding, along with the March 4 and June 17, 1987, occurrences discussed above, indicates that the Operations Department historically has not linked sequencer outages to the LCOs of TS 3.3.2 or TS 3.0.3. Nevertheless, discussions with the operations manager and the licenced operators on shift indicated that although no written guidance or TS interpretation existed for the sequencers, the Operations Department staff would currently consider all applicable TS requirements, including TS 3.3.2 and 3.0.3.

Conclusion

The LCO actions of TS Table 3.3-2, "ESFAS Instrumentation," are applicable for determining the operability of ESFAS components; however, if a load sequencer is not operable, the more restrictive requirement of TS Table 3.3-2, TS 3.0.3, or the affected system LCO should be considered. Although the EDG LCO of TS 3.8.1.1.b had been used for sequencer outages in the past, the allegation's concern of possibly exceeding the LCO for TS 3.0.3 when the sequencers were previously deenergized were not confirmed.

Because there is no specific TS for the sequencers and considering (1) their unique interaction with numerous other systems and equipment, and (2) the varying degrees in which related failures, maintenance work, and surveillances can affect the sequencers' associated functions, the inspection team concluded that additional guidance for the operators is warranted. Therefore, this issue will be followed as an inspector followup item pending further review and evaluation and is identified as IFI 50-424,425/90-19-15: "Lack of Operator Guidance Concerning the LCO Actions Applicable During ESFAS Sequencer Outages."

Exhibit 83, page 13 of 17

2.5 Air Quality of Emergency Diesel Generator Starting Air System

An allegation indicated that VEGP had no basis for its conclusions regarding the air quality of the EDG starting air system and misrepresented the air quality in the licensee's written response to the Confirmation of Action Letter (CAL) dated March 23, 1990.

Discussion

The inspection team reviewed the maintenance records and deficiency cards associated with Unit 1 EDG starting air system. The team noted that the maximum dewpoint reading of 50 degrees Fahrenheit was established when preoperational tests were initially performed on Unit 1 in November 1986. Dewpoint measurements were taken after this date, but not on a scheduled frequency. During the latter part of 1988, a monthly preventive maintenance (PM) schedule was established to measure the EDG starting air system dewpoint. The current PM program required checking the dewpoint monthly, cleaning the air dryer condensing units, and cleaning the fan motors. In addition, Operating Procedure 11882-1, "Outside Area Rounds," required that the EDG starting air system air receivers and air dryers be blown down on a daily basis until they were free of moisture. The inspection team verified that the plant equipment operators blew down the air systems on each shift during the performance of their rounds.

A review of the Unit 1 EDG maintenance history records indicated that the majority of the dewpoint measurements taken were within specifications. There were instances, however, when the dewpoint measurements were above specifications. These conditions were primarily attributed to problems with (1) the dewpoint measuring instruments, (2) system air dryers being out of service for extended periods of time, and (3) repressurizing the EDG air start system following maintenance.

The inspection team reviewed maintenance records associated with an internal inspection of the EDG air start system air receiver, 5-micron control air system filter inspection and replacement, and the replacement of the dewpoint measuring instrument with an EG&G analyzer. Following the loss of offsite power event of March 20, 1990, the control air system instrument lines were disconnected for maintenance troubleshooting and functional tests of Calcon sensors. The system engineers associated with this work stated that no evidence of internal moisture or corrosion was noted during inspection and calibration of the Calcon sensors or the control air system instrument lines when this equipment was disconnected for maintenance troubleshooting and testing.

Conclusion

The inspection team concluded that the licensee did have an adequate basis to assess the quality of the EDG starting air system. This was based primarily upon the records of the visual inspection of EDG air start system components for degradation. In addition, the PM program dewpoint readings have shown more consistency since the licensee changed over to an EG&G analyzer. The allegation that GPC did not have a basis for their statements and misrepresented the air quality in the licensees written response to the CAL, was not confirmed.

2.6 Reportability of Previous System Outages

An allegation indicated that VEGP failed to immediately notify the NRC as required by 10 CFR 50.72 when VEGP identified that both trains of the containment fan coolers (CFCs) had been previously inoperable at the same time on Unit 1.

Discussion

The inspection team's review of plant records indicated that this condition occurred when EDG #1A was declared inoperable when tape (used when the EDG was being painted) was found on the EDG fuel rack. The tape kept the fuel injector piston from moving and injecting fuel into the EDG. With EDG #1A inoperable, the equipment associated with the Train A was also inoperable. In the process of investigating the installation of the tape, VEGP identified that this condition existed during a period when the Train B containment fan coolers were also in a degraded condition for maintenance.

During the performance of Surveillance Procedure 14623-1, Train B containment fan cooler (CFC) 1-1501-A7-003 failed to start in slow speed. LCO 1-90-560 was initiated at 1:15 a.m. on June 19, 1990, and maintenance on the CFC was initiated. The CFC was returned to operable status on June 19, 1990, at 2:15 p.m. Approximately 9 hours later [on June 19, 1990, at 11:59 p.m. (LCO 1-90-562)], EDG #1A was determined to be inoperable because the tape had been installed on the fuel rack. On July 17, 1990, VEGP issued LER 90-014 to identify the previously unrecognized violation of the LCO in accordance with 10 CFR 50.73.

Conclusion

Based upon the fact that VEGP did not become aware that both trains of CFCs were simultaneously inoperable until after the Train B CFC fan had been returned to service, the immediate notification requirements of 10 CFR 50.72 were not applicable. The allegation that VEGP failed to immediately notify the NRC upon discovery of the previously degraded condition of the CFCs was not confirmed.

2.7 Intimidation of Plant Review Board Members

An allegation indicated that PRB members were allegedly intimidated and pressured by the general manager in a PRB meeting. The meeting occurred in February 1990, to determine the acceptability of the safety analysis for the installation of the FAVA microfiltration system.

Discussion

As discussed in Section 2.1 of this inspection report, several safety evaluations were performed for the installation of a temporary modification which installed the FAVA microfiltration system. Discussions with PRB members indicated that during the review of these safety evaluations, various PRB members had expressed reservations on several occasions concerning the acceptability of the installation of the FAVA system.

Despite these reservations, the inspection team's review of the PRB Meeting minutes associated with this temporary modification identified few instances of the PRB members documenting their dissenting opinions. Specifically, PRB meeting 90-15 (dated February 8, 1990) documented one PRB member's negative vote and dissenting opinions regarding the acceptability of exempting the temporary modification from regulatory requirements and the adequacy of the system's safety evaluation. PRB Meeting 90-28 (dated March 1, 1990) indicated that information and issues regarding the FAVA system's safety analysis were presented to the PRB and that the general manager solicited written comments and questions from other members for resolution. The only other example was in PRB meeting 90-32 (dated March 6, 1990) which identified a dissenting opinion related to the acceptability of voting on the FAVA system installation when the PRB member who raised the initial questions and concerns on the operation of the FAVA system was not present.

Discussions with the PRB members indicated that during the various PRB meetings concerning the installation of the FAVA system, the PRB members felt intimidated and pressured by the presence of the general manager at the PRB meeting. The sworn testimony confirmed that on one occasion an alternate voting member felt intimidated and feared retribution or retaliation because the general manager was present at the meeting and the PRB member knew the general manager wanted to have the temporary modification approved. However, the testimony also indicated that the PRB member did not alter his vote and felt comfortable with how he had voted. In addition, the PRB member was not aware of any occasions on which he or any other PRB member had succumbed to intimidation or feared retribution.

The inspection team verified that the general manager was informed following this meeting that several PRB members viewed his presence as intimidating. As a result, on March 1, 1990, the general manager met with all PRB members to reiterate the member's duties and responsibilities. He specifically told the members that his presence at PRB meetings must not influence them and that alternates should be selected who would feel comfortable with this responsibility. He also addressed the difference between professional differences of opinion and safety or quality concerns, and their respective methods for resolution.

Conclusion

The inspection team concluded that in one case a PRB voting member felt intimidated and feared retribution because the general manager was present at the PRB meeting. However, this member stated that he did not change his vote in response to this pressure and the general manager met with the PRB to allay fears. Based on the testimony, the inspection team concluded that retribution did not occur. Nevertheless, this confirmed event and the absence of dissenting opinions in the PRB meeting minutes indicate that there was a potential for an adverse affect on open discussions at the meeting. The licensee needs to ensure that PRB members freely and openly express their technical opinions and safety concerns.

2.8 Personnel Accountability

As a result of several comments and questions by the licensed operators to the inspection team, the team reviewed the method used to rate the performance of the shift superintendents (SS) and unit shift supervisors.

Discussion

The operations manager stated that the SS reported directly to the operations manager and that he personally prepared their performance appraisals. The inspection identified that the SS reported to the Unit Superintendent (US), and that the US personally prepared the performance appraisals of the SS.

The personnel accountability system, first used in 1989, was a pay-for-performance methodology. Annual pay increases and a percentage of the Operations Department bonus were dependent on their ratings in accountability categories. Each accountability category was subdivided into performance categories. Most of the performance categories were based upon group performance. Once these are eliminated, any differential in pay will result from eight performance categories. Implementation of the plan in 1989 could result in up to an $8,000-a-year difference in bonus pay to a SS. The performance categories and their relative weights are:

- Personnel safety	4.1%
- Regulatory compliance	10.2%
- ESFAS actuation	12.2%
- Reactor trips	10.2%
- MWO performance	4.1%
- Special projects	8.2%
- Personnel development	30.6%
- Training	20.4%

Therefore, 51 percent will be associated with personnel development and training and 32.6 percent will be associated with the number of LERs, and violations [i.e., regulatory compliance (10.2 percent), ESFAS actuation (12.2 percent) and reactor trips (10.2 percent)].

Conclusion

The inspection team concluded that there was a potential disincentive for identifying items which may result in LERs or violations. In addition, the inspection team concluded that the operations manager provided incorrect or inadequately researched information to the inspection team. The inaccurate information concerned whether the operations manager personally performed the performance appraisals of shift superintendents. The inspection team identified that this failure to provide accurate information is an example of an apparent violation of the 10 CFR 50.9 requirements to provide accurate information to the NRC and will be identified as an example of Violation 50-424,425/90-19-12: "Failure to Provide Accurate Information as Required by 10 CFR 50.9 to the NRC."

3.0 EXIT INTERVIEWS

The inspection scope and findings were summarized on August 17, 1990, with those persons indicated in Appendix 2. 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

LIST OF TRANSCRIBED INTERVIEWS

DATE	TIME	PERSON
8/14/90	904 hours	George Bockhold
	911 hours	Jim Swartzwelder
	1023 hours	Harvey Handfinger
	1026 hours	Bill Diehl
	1109 hours	Mike Horton
	1335 hours	Mike Chance
	1136 hours	Jimmy Paul Cash
	1338 hours	Dudley Carter
	1529 hours	Bruce Kaplan
	1625 hours	Greg Lee
	1800 hours	Jeff Gasser
8/15/90	906 hours	Allen Mosbaugh
	937 hours	Ernie Thornton
	1009 hours	John Gwin
	1048 hours	Steve Waldrup
	1335 hours	Jerry Bowden
	1452 hours	John Williams
	1637 hours	Carolyn Tynan
	1730 hours	John Williams

APPENDIX 2

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, 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, Georgia Power Company
*R. McDonald, Executive Vice-President, Georgia Power Company
*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 16, 1990.

APPENDIX 2

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 3

LIST OF ACRONYMS

AOP	Abnormal Operating Procedure
ARB	Alternate radwaste building
ASME	American Society of Mechanical Engineers
CAL	Confirmation of action letter
CFC	Containment Fan Cooler
CFR	Code of Federal Regulations
DC	Deficiency card
DRP	Division of Reactor Projects
EDG	Emergency diesel generator
EPRI	Electric Power Research Institute
ESF	Engineered safety features
ESFAS	Engineered safety features actuation system
FAVA	FAVA Control Systems
FSAR	Final Safety Analysis Report
HUT	Holdup tank
I&C	Instrumentation and controls
IFI	Inspector followup item
IST	Inservice test
kV	Kilovolt
LCO	Limiting condition for operation
LER	Licensee Event Report
MWO	Maintenance work order
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSCW	Nuclear service cooling water
NSSS	Nuclear steam supply system
OI	Office of Investigations
PM	Preventative maintenance
PRB	Plant Review Board
psig	Pounds per square inch gauge
PVC	Polyvinyl chloride
QA	Quality Assurance
RII	Region II Office
RCS	Reactor coolant system
REA	Request for engineering assistance
RG	Regulatory Guide
RHR	Residual heat removal
SER	Safety Evaluation Report
SI	Safety injection
SONOPCO	Southern Nuclear Operating Company
SS	Shift superintendent

Exhibit ____, page ____ of ____

APPENDIX 3

LIST OF ACRONYMS (continued)

TCP	Temporary change to procedure
TS	Technical Specification
US	Unit Superintendent
USS	Unit shift superintendent
UV	Undervoltage
VEGP	Vogtle Electric Generating Plant