APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

NRC Inspection Report: 50-285/90-32 License: DPR-40

Docket: 50-285

Licensee: Omaha Public Power District (OPPD)
444 South 16th Street Mall
Omaha, Nebraska 68102-2247

Facility Name: Fort Calhoun Station (FCS)

Inspection At: FCS, Blair, Nebraska

Inspection Conducted: June 17 through July 28 and August 1, 1990

Inspectors: P. Harrell, Senior Resident Inspector
T. Reis, Resident Inspector

Approved: Blaine Murray for G. L. Constable, Chief, Project Section C 8/16/90 Date

Inspection Summary

Inspection Conducted June 17 through July 28 and August 1, 1990 (Report 50-285/90-32)

Areas Inspected: Routine, unannounced inspection of onsite followup of events; operational safety verification; monthly maintenance, surveillance, security, and radiological protection observations; review of licensee event reports; and in-office review of reports.

Results: The licensee experienced several plant perturbations during this inspection period. These consisted of a turbine trip, an emergency diesel generator (EDG) failure, a failure of a resistance temperature detector in a reactor regulating system control channel, and a loss of power to the control instrumentation for pressurizer pressure and pressurizer level. Licensed operator response to each of these perturbations was efficient, technically correct, and conservative. The efficient response and recovery from each of these incidents was indicative of the high experience and knowledge level of the licensed operators. Strong support for operations through these events was evident.

A problem with high ambient air temperatures affecting EDG operability recurred. The licensee's engineering organization responded well to this challenge. This had been an ongoing source of investigation. The licensee was able to produce quantitative data demonstrating the operability of the EDGs and had in place plans for additional testing to prove the reliability of their existing data.

However, the licensee appears to have not met Technical Specification (TS) requirements for verifying that emergency loads on the EDGs do not exceed the 2000 hr-kW rating. The test performed to satisfy this requirement during the last refueling outage was apparently inadequate. A violation has been cited in this report (paragraph 3.a).

An unresolved item was identified (paragraph 3.a) regarding EDGs design basis load. Two inspector followup items concerning installation of a resistance temperature detector and use of alternate control channels are discussed in paragraphs 5.b and 5.c.

DETAILS

1. Persons Contacted

 J. Bobba, Supervisor, Radiation Protection
*J. Chase, Manager, Nuclear Licensing and Industry Affairs
 S. Gambhir, Division Manager, Production Engineering
*W. Gates, Division Manager, Nuclear Operations
*K. Holthaus, Manager, Nuclear Engineering
*R. Jaworski, Manager, Station Engineering
 J. Kecy, Supervisor, Systems Engineering
*L. Kusek, Manager, Nuclear Safety Review Group
*M. Lazar, Supervisor, Operations Training
 D. Matthews, Supervisor, Station Licensing
*T. Matthews, Station Licensing Engineer
*W. Orr, Manager, Quality Assurance and Quality Control
*T. Patterson, Assistant Manager, Fort Calhoun Station
 G. Peterson, Manager, Fort Calhoun Station
 A. Richard, Assistant Manager, Fort Calhoun Station
*J. Sefick, Manager, Security Services
 C. Simmons, Station Licensing Engineer
*J. Tills, Assistant Manager, Fort Calhoun Station
 D. Trausch, Supervisor, Operations

*Denotes attendance at the exit interview conducted on August 1, 1990.

The inspectors also contacted other plant personnel.

2. Plant Status

The inspection period began with the unit operating at full power. On June 22, 1990, a planned power reduction to below 12 percent was initiated to facilitate balancing a bearing on the main turbine. During power ascension, subsequent to the balancing, a turbine trip resulted. The turbine was reloaded and the unit brought to 95 percent power by June 25, 1990.

On June 25, 1990, prolonged EDG 1 testing resulted in the failure of the EDG 1 voltage regulator due to high temperature. EDG 1 was shut down and declared inoperable. A common failure mechanism left the reliability of EDG 2 in doubt. A controlled plant shutdown was initiated on June 26, 1990, but was stopped at 42 percent. Engineering had determined that a simple, temporary modification would prevent the common failure mechanism. On June 27, 1990, the unit regained 100 percent power operation after the diesel generator operability concern was resolved. The unit remained at full power for the duration of this inspection period.

On July 26, 1990, a loss of power to control instruments was experienced. The event caused both pressurizer pressure and level to increase, but no limits were exceeded. Licensed operators recovered from the transient by taking alternate channel control within minutes from initiation of the event.

3. Onsite Followup of Events (92702)

a. During the summer months of 1989, high ambient air temperatures, compounded by uninsulated exhaust lines, caused the potential for the EDGs to exceed the upper limit on jacket cooling water temperatures. Testing demonstrated that the limiting jacket cooling water temperatures were correlated to ambient temperatures of 97°F and 100°F for EDG 1 and EDG 2, respectively. This condition resulted in the EDGs being declared inoperable if the referenced temperatures were met or exceeded.

The EDG cooling system consists of an engine radiator, an engine-driven fan, and a pump that circulates cooling water through the engine. Outside air is drawn into the EDG room by the fan and is blown across the radiator and exits through the roof of the auxiliary building via air ducts. When the air is drawn from outside into the EDG room, the air becomes preheated prior to passing through the radiator due to the heat emitted by the engine and, previously, the uninsulated exhaust line. Due to preheating, the temperature of the air passing through the radiator can be as high as 20°F hotter than the outside ambient air temperature. This temperature increase affected the ability of the jacket cooling water system to maintain the temperature of the water exiting the engine at or below 208°F, the maximum allowable water temperature established by the engine manufacturer. As a result, ambient temperature limits (97°F for EDG 1 and 100°F for EDG 2) were established for EDG operability.

To address the problem, the licensee insulated the engine exhaust line, during the 1990 refueling outage, to reduce the temperature of the air entering the radiator. During the 1988 refueling outage, the licensee had removed the insulation on the EDG exhaust line because the insulation contained asbestos. The insulation was not replaced due to the impact on the length of the outage.

After the exhaust line was reinsulated, on June 25, 1990, the licensee performed an extended run on EDG 1 to establish a temperature profile for the EDG room in an effort to raise the outside ambient temperature limit for EDG operability.

The inspectors reviewed the data that the licensee used to establish the ambient temperature limit for EDG 1. The load profile used to determine the limit was derived from a calculation (FC-89-026) that was issued by the licensee in August 1989.

In lieu of reperforming the calculation after the 1990 refueling outage to determine the loading on the EDGs, the licensee opted to run the EDGs with the emergency loads on the bus to verify the load profile in accordance with requirements provided in Procedure ST-ESF-6, "Diesel Start and Diesel Fuel Oil Transfer Pump." At the time the load verification was done, the plant was in cold shutdown and the reactor coolant system was depressurized. The load profile established by operation of equipment with the plant shut down did not reflect the load profile that the EDGs would experience following a loss-of-coolant accident (LOCA). Therefore, the load verification performed by the licensee did not appear to comply with TS requirements. TS 3.7(1)c.iii requires verification that EDG emergency loads do not exceed the 2000-hour kW rating. The licensee's failure to verify the loading on the EDGs, using an appropriate method, is an apparent violation of TS 3.7(1)c.iii. (285/9032-01)

In NRC Inspection Report 50-285/89-32, issued on September 28, 1989, a noncited violation (NCV) was documented for failure to properly implement a test procedure for verification of EDG emergency loads. At the time the NCV was documented, the licensee committed to change the EDG surveillance tests to incorporate the requirements of TS 3.7(1)c.iii. It did not appear that an appropriate test was implemented by the licensee.

In response to the issues regarding the capability of the EDGs to carry the design basis loads, as required by Section 8.4.1 of the Updated Safety Analysis Report, the Division Manager, Production Engineering (DMPE), committed to perform an indepth and comprehensive evaluation of the EDG postaccident electrical loading and the effect of elevated ambient temperatures on EDG operability. The DMPE stated that the evaluation would be completed and submitted to the NRC on o before August 31, 1990. This item will be tracked as an unresolved item pending a review of the evaluation by the NRC staff. (285/9032-02)

b. In addition to reviewing Procedure ST-ESF-6, the inspector also reviewed the emergency operating procedures (EOP) to verify that appropriate instructions had been provided to operations personnel with respect to placing additional loads on the EDGs after safety-related equipment had been automatically started in response to a LOCA. For example, the EOPs instructed operations personnel to start an air compressor (approximately 125 kW) after loads had been automatically sequenced on to the EDG bus.

During review of the EOPs, the inspector noted a weakness in that the EOPs did not instruct operations personnel to verify loading on the EDG prior to placing additional loads on the bus. Without prior verification, the possibility existed that the EDGs could be overloaded when additional equipment was started.

To address this concern, the licensee issued a revision to Procedure EOP-20, "Functional Recovery Procedure," on June 30, 1990. The revised instructions provided a caution to operations personnel to ensure that EDG ratings are not exceeded. The actions taken by the licensee appeared to address this concern.

Problems with the content of EOPs were identified by the NRC during a previous inspection and documented in NRC Inspection Report 50-285/89-40. The licensee was in the process of reviewing and revising, as necessary, the EOPs at the end of the inspection period. An EOP team inspection was scheduled to be performed in August 1990, and this team will review the adequacy of the EOPs.

c. During an extended run of EDG 1, the voltage regulator failed and EDG 1 was stopped. When the system engineer opened the doors for the cabinet containing the voltage regulator circuitry, he noted that the cabinet was extremely hot. The licensee did not measure the temperature in the cabinet; however, the engineer had to withdraw his hand quickly because of the high temperature of the cabinet. EDG 1 was declared inoperable.

To reestablish EDG 1 operability, the licensee replaced a transistor in the voltage control circuitry and removed the doors on the control circuitry cabinet to provide ventilation for the cabinet. The cabinet, as originally installed, was totally enclosed and unventilated. In addition, the licensee also removed the doors for the EDG 2 circuitry cabinet. The removal of the cabinet doors was performed based on the generation of Temporary Modification (TM) 90-019. The 10 CFR Part 50.59 evaluation completed for the TM indicated that additional failure mechanisms, other than those previously analyzed, were not introduced with respect to potential damage to the exposed regulator circuitry.

The surveillance test for EDG 1 was successfully performed after the transistor in the voltage regulator circuit was replaced and EDG 1 was declared operable.

With respect to the affect of the high temperatures on the electronic components inside the cabinet, the licensee contacted the vendor, General Electric, to determine the appropriate actions to take. In an internal licensee memorandum (PED-FC-90-1287), dated July 11, 1990, the licensee documented the vendor's position that the electronic components do not experience significant aging characteristics and that nonfailed components do not require replacement. Based on this information, the licensee does not plan on taking additional actions with the voltage regulator circuitry.

At the end of the inspection period, the licensee was examining permanent modifications to the cabinet which houses the voltage regulator and static exciter. No decision had been made as to how the cabinet would be modified to ensure adequate cooling to the circuitry.

No deviations were identified in this area; however, one violation and one unresolved item were identified.

4. Operational Safety Verification (71707)

The inspectors conducted reviews and observations of selected activities to verify that facility operations were performed in compliance with the appropriate regulatory requirements.

On June 22, 1990, the licensee commenced a plant shutdown to facilitate repair of excess vibration on the No. 8 turbine bearing. The bearing had exhibited higher than normal vibration since the plant was restarted on May 29, 1990, after the refueling outage. General Electric, the turbine generator manufacturer, recommended taking the unit off line to balance the bearing.

The inspector observed the plant shutdown and found it to be well controlled and performed in accordance with Procedure OP-5, "Plant Shutdown." The inspector witnessed the turbine being taken off-line when reactor power was 8 percent. The evolution was performed per Procedure OI-ST-3, "Turbine Generator Shutdown." All systems functioned as designed and the maneuver was performed in a conscientious, controlled manner. The licensee used the opportunity to perform the annually-required turbine overspeed trip test per Procedure OI-ST-10, "Turbine Generator Tests." The overspeed trip functioned as de[illegible]ned. The turbine bearing was balanced, and other unrelated outage w[illegible]ompleted, on June 23, 1990, and power ascension began. At 12 percent r[illegible] power, the licensee attempted to synchronize the generator to [illegible]d. The licensee experienced difficulty in getting Breaker 3451-4 to close. The control relay had been adjusted during the refueling outage and the margin available for synchronization had been reduced. The licensed reactor operator held the handswitch for Breaker 3451-4 in the closed position; however, the breaker did not close. A turbine trip resulted. The operator was not aware of a design function where, if a mismatch between demanded position and actual position existed for more than 3 seconds, a turbine trip would result.

An internal investigation by the operations staff found that very few personnel were aware of the design feature. It was not covered in training nor was it proceduralized.

As corrective action, the licensee revised Procedure OI-ST-9, "Generator Excitation System, Synchronization Procedure and Operating Guidelines," to provide the information on the design feature as a caution statement preceding the synchronization step. The trainin[illegible] department also developed and issued a training "hotline" to all license [illegible]lders and shift technical advisors which adequately addressed the to[illegible]

On June 25, 1990, the generator was satisfactorily placed on the grid. A normal power ascension to 95 percent was performed.

No violations or deviations were identified in this area.

5. Monthly Maintenance Observations (62703)

The inspector observed selected station maintenance activities on safety-related systems and components.

a. On July 16-17, 1990, the inspector observed selected portions of the performance testing of EDG 2. The work was performed under the direction of Maintenance Work Order (MWO) 902170 and Special Procedure SPC 33116, "Test Procedure Number T-2, Detailed Testing Program, EDG 2 Jacket Water System Temperature Profile." The purpose of performing the procedure was to permit extensive testing of EDG 2 for the collection of data to determine the maximum ambient temperature at which the EDG can be fully loaded without exceeding an internal coolant temperature of 208°F.

   Two sets of data were obtained. On July 16, 1990, the EDG was run fully loaded for approximately 5 hours with an ethylene glycol/water mix as the coolant and, on July 17, 1990, an identical test was run with pure water plus a corrosion inhibitor as the coolant. Since water has a higher thermal conductivity value than ethylene glycol, it was expected to enhance the radiator's cooling performance. However, the test data indicates no improvement and the limiting ambient temperature for either cooling option was determined to be 103°F. This is a 3°F improvement over the previous limit of 100°F. Test results also demonstrated the limiting ambient air temperature for EDG 2 to be 107°F. Both EDGs will use the water/corrosion inhibitor as a coolant until the fall.

   The licensee performed this testing in a sophisticated manner. A temperature logger was procured which reads and records the temperatures sensed by 83 thermocouples strategically positioned on various components and areas of the EDG. The licensee recorded the measurements in 5-minute intervals for approximately 5 hours.

   The effort expended in performing this extensive testing demonstrated the thoroughness and significance the engineering organization applied to the EDG problem. The data collected will serve as meaningful input to any subsequent modifications necessary relative to this problem.

b. On July 14, 1990, the licensee experienced a failed-high, resistance temperature detector (RTD) in the Loop 1 hot leg. The RTD (TI-111H) provides input to the reactor regulating system (RRS) which provides control functions only. The RRS computes a Tavg value from the hot and cold leg RTD inputs. This Tavg is then provided as an input to the pressurizer level program, the steam dump program, and various deviation alarms.

   Under full-power conditions, the RTD failure does not adversely affect operations other than to illuminate annunciators which indicate a high temperature, a mismatch between Loops 1 and 2, and a mismatch between programmed Tavg or Tref and actual Tavg.

As temporary corrective actions, the licensee installed a resistor in the RTD circuitry in place of the RTD to provide a "dummy" input signal that corresponds to the value that the RTD would read at full power.

The false signal had no effect on full-power operations. In the event of a turbine trip in this condition, the steam dump and bypass valves would go full open, when Channel A of the RRS is selected, because of the high Tavg resulting from TI-111H providing a constant reading.

The operators were informed of this vulnerability on July 20, 1990, via the "Night Notes" turnover mechanism. Additionally, the RRS selector switch had been "Caution Tagged" as had the TI-111H meter

The resistor was installed in the circuitry in accordance with TM 90-020, "Decade Box Resistor Installed in Place of TI-111H." The inspector reviewed the 10 CFR Part 50.59 safety evaluation performed for the modification. The inspector agreed with the licensee's determination that operation with the installation did not constitute an unreviewed safety question.

The modification was a short-term installation. To operate for the remainder of the fuel cycle, the licensee was designing a modification that would tap into an alternate, operable, RTD. The review of the forthcoming installation is considered an inspector followup item. (285/9032-03)

c. On July 26, 1990, safety-related Inverter A switched to its bypass transformer. Simultaneously, operators realized they had lost control power to pressurizer pressure and level control and had lost letdown flow. The cause of the inverter switchover, and loss of power, appeared to be correlated to a ground caused by a craftsman performing a preventive maintenance activity on Charging Pump Suction Pressure Control Switch 226.

Operators promptly regained pressurizer pressure and level control by selecting the opposite channel, where power was available. The temporary loss of the control systems caused pressurizer pressure to reach 2170 psig and pressurizer level to reach 62 percent. Normal setpoints for 100 percent power are 2100 psig and 60 percent, respectively. The pressure increased because the pressurizer backup heaters energized when the pressure control channel failed low. Channel A of the reactor protection system (RPS) received a trip on variable overpower. No actual overpower occurred. The tripped channel appeared to be the result of the electrical transient.

Approximately 40 minutes after the event, electrical maintenance traced the cause of the control failure to a blown fuse. The fuse was promptly replaced and the circuitry tested with no faults indicated. Forty-eight minutes after the transient, Inverter A was placed back in service.

The inspector reviewed the preventive maintenance procedure, in conjunction with the instrumentation and control diagram, for the calibration of Charging Pump Suction Pressure Control Switch 226. The inspector noted that the loss of letdown flow and activation of the pressurizer backup heaters could have been prevented had operations simply switched to the alternate control channels prior to releasing the instrument for preventive maintenance.

The inspector considered that the preventive maintenance procedures, as well as other technical work documents, could be prepared in such a manner as to alert operations to switch to alternate control channels in many cases. The licensee agreed that the concept would be a safety enhancement and agreed to investigate the scope of the enhancement and implement it, if feasible. The inspector will reexamine the licensee's efforts in this area. This is considered an inspector followup item. (285/9032-04)

No violations or deviations were identified in this area.

6. Monthly Surveillance Observations (61726)

The inspectors observed TS-required surveillance testing on safety-related systems and components.

a. On July 6, 1990, the inspector witnessed selected portions of Special Procedure SP-FW-17, "Auxiliary Feedwater Full Flow Recirculation Test." The test was developed to:

   - Calibrate the back pressure trip device on the turbine-driven auxiliary feedwater pump (FW-10).
   - Develop performance curves for both the motor-driven (FW-6) and turbine-driven (FW-10) auxiliary feedwater pumps.
   - Verify the ability of FW-10 to start and function with only a single steam supply available.
   - Determine a reference speed and obtain baseline data for future testing of FW-10 per the ASME Code.
   - Determine the amount of warmup steam flow to FW-10 and obtain baseline data to determine the accuracy of flow control through the line bypass valves.

   The test criteria addressed generic concerns of auxiliary feedwater system pumps identified by the Institute of Nuclear Plant Operations. The test was developed by special services engineering and implemented by system engineering.

   The inspector found the implementation of the procedure to be well coordinated. Prejob briefings were conducted periodically for each segment of the test. As the pumps were individually taken out of service for testing, operations entered the appropriate TS limiting condition for operation. Operability of the alternate pump was verified prior to removing either FW-10 or FW-6 from service. Good communications were established between system engineering, control room operators, turbine building operators, and the craft.

b. On July 2, 1990, the inspector witnessed a licensed reactor operator perform Procedure OP-ST-CEA-003, "Control Element Assembly (CEA) Partial Movement Check." The test procedure was designed to satisfy, on a biweekly basis, the requirements of TS 3.2, Table 3-5, Item 2. The test required that each CEA be exercised a minimum of 6 inches and be returned to its initial position. Since the FCS was operating in the all-rods-out mode; each assembly was inserted 6 inches and then withdrawn to the full-out position. The inspector witnessed that all equipment functioned as designed and the test results were appropriately documented.

c. The inspector also witnessed portions of the performance of Procedure OP-ST-CEA-004, "Secondary CEA Position Indication System Test." The test procedure was designed to satisfy, on a monthly basis, the requirements of TS 3-1, Table 3-3, Item 2(b). The secondary control element assembly position indication system utilized the output of a voltage divider network controlled by a series of reed switches. The reed switches were actuated by a permanent magnet attached to the CEA. This test was performed by simulating rod movement through a computer program. All equipment functioned as designed and the test was satisfactorily completed.

No violations or deviations wer identified in this area.

7. Security and Radiological Protection (RP) Observations (71707)

The inspectors verified that the physical security plan and RP program were being implemented.

a. On numerous occasions, the inspector toured the radiation controlled area and noted that the licensee had taken action to clean the areas that had been contaminated during the refueling outage that ended on May 29, 1990.

b. On July 18, 1990, the inspector was notified by the licensee's security organization of an incident involving a safeguards vault being left open and unattended. The safeguards container was located within a monitored, vital area. As such, the licensee was able to monitor access and egress to the area. The security computer database demonstrated that an individual, not authorized access to safeguards information, was in this vital area during the time the safeguards container was left open and unattended. The licensee initially believed that this apparent compromise of safeguards information constituted a reportable event pursuant to the provisions of 10 CFR Part 73, Appendix G. The licensee promptly notified the NRC.

The licensee interviewed the individual who had been in the vital area and performed a search of his person. The individual denied looking in the safe and the search results were negative. The individual agreed to submit to a polygraph examination. The result of the examination substantiated the individual's spoken word.

As a result of the investigation, the licensee determined that the safeguards information was not compromised. After discussion with the Region IV Division of Radiation Safety and Safeguards on July 23, 1990, the licensee withdrew the 1-hour report. The determination was reached that this situation was only reportable if it was determined that safeguards material was compromised; otherwise, it was a logable event.

No violations or deviations were identified in this area.

8. Licensee Event Report (LER) Followup (92700)

The following event report was reviewed to determine that reportability requirements were fulfilled, corrective actions were accomplished, and actions were taken to prevent recurrence.

(Closed) LER 90-011 reported an event where an inadvertent engineered safety feature (ESF) actuation occurred due to inappropriate action on the part of an instrumentation and control (I&C) technician performing a calibration procedure. At the time of the occurrence, the reactor was defueled and containment integrity was not required. The safety significance of the actuation was minimal. The event was fully documented in paragraph 10.k of NRC Inspection Report 50-285/90-13. The inspector considers the licensee's action adequate to close LER 90-011.

The event caused an apparent weakness in the licensee's verification and validation (V&V) process of its new (Project 1991) procedures to surface. The technician performing Calibration Procedure CP-B/102, "Pressurizer Pressure Channel 102," caused the actuation by lifting a lead, which caused the unblocking of the pressurizer pressure low signal (PPLS) circuitry. Procedure CP-B/102 did not direct the technician to lift the lead, but the new procedure intended to replace CP-B/102 did. The technician was referring to Procedure IC-ST-RC-0026, "Channel Calibration of Pressurizer Pressure Loop B/P-102," for guidance. The new procedure had not yet been approved but had been through the V&V process. This indicated that the new procedure had been inadequately drafted, verified, and validated.

As corrective action the licensee has:

- Revised the Project 1991 procedures for the four PPLS channel calibrations to eliminate the need for lifted leads.
- Provided training via the "Hotline" mechanism to all electrical and I&C procedure writers, system engineers, and craft personnel

participating in the V&V process. This training emphasized the importance of verifying the results of lifting leads required by the upgraded procedures.

° Reexamined all previously validated Project 1991, I&C procedures affecting ESF or RPS components to ensure analogous situations did not exist.

The inspector reviewed the corrective actions taken by the licensee and held interviews with representatives from the procedures upgrade project, system engineering, and I&C personnel involved in the V&V process. Programmatically, the V&V process appeared to be strong. The corrective actions taken by the licensee appropriately addressed the concerns raised by the inspector.

No violations or deviations were identified in this area.

9. In-Office Review of Licensee Reports (90712 and 90713)

NRC Region IV personnel identified a 10 CFR Part 21 report submitted by a vendor that appeared to be applicable to the licensee's facility. The resident inspector provided a copy of a report issued by the Dresser Valve Company, dated May 18, 1990 (Region IV Log No. 90-10), concerning Dresser's 1566 Hydroset new valve constant K factors, to the Supervisor, Station Licensing, for review of applicability by the licensee.

10. Unresolved Item

An unresolved item is one about which additional information is required in order to determine if it is acceptable, a deviation, or a violation. There is one unresolved item in this report.

Paragraph	Item No.	Subject
3.a	285/9032-02	EDG Capability to Carry Design Loads

11. Exit Interview (30703)

The inspector met with Mr. W. G. Gates (Division Manager, Nuclear Operations) and other members of the licensee staff on August 1, 1990. The meeting attendees are listed in paragraph 1 of this inspection report. At this meeting, the inspector summarized the scope of the inspection and the findings. During the exit meeting, the Manager, Fort Calhoun Station, confirmed the commitment identified in the cover letter to this inspection report with respect to switching control channels during maintenance activities and evaluation of the design basis loads for the EDGs. The licensee did not identify as proprietary any of the material provided to, or reviewed by, the inspectors during this inspection.