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GPC EXHIBIT II-171-B
WEBB EX. C.2

LER 1-90-[illegible]

DOCKETED
USNRC

'95 OCT 20 P3:06

OFFICE OF SECRETARY
DOCKETING & SERVICE
BRANCH

LOSS OF OFFSITE POWER LEADS TO SITE AREA EMERGENCY

EVENT DATE: 3-20-90

ABSTRACT

On 3-20-90, Unit 1 was in a re-fueling outage and Unit 2 was operating at 100% power. At 0820 CST, a fuel truck in the switchyard backed into the support holding a "C" phase insulator for Unit ~~the~~ Reserve Auxiliary Transformer (RAT) 1A. The insulator and line fell to the ground, causing a phase to ground fault. Both RAT 1A and ~~the~~ Unit 2 ~~Train B~~ RAT H1 Side and Low Side breakers tripped, causing a loss of offsite power condition (LOSP), ~~since the Unit 1 Train B RAT and DG were out of service for maintenance.~~ Both units' emergency Diesel Generators (DG's) started, but the Unit 1 DG tripped, causing a loss of residual heat removal (RHR) to the reactor core. A Site Area Emergency (SAE) was declared and the site Emergency Plan was implemented. The core heated up to 136 degrees F before the DG was emergency started at 0856 CST and RHR restored. At 0915 CST, the SAE was downgraded to an Alert after onsite power was restored.

The direct cause of these series of events is a cognitive personnel error. The truck driver failed to use proper backing procedures in the switchyard and hit a support, causing the phase to ground fault and LOSP. The most probable cause of the DG1A trip is the intermittent actuation of the DG jacket water temperature switches.

Corrective actions include strengthening policies for control of vehicles, extensive testing of the DG and replacement of suspect switches.

NUCLEAR REGULATORY COMMISSION

Docket No. 50-424/425-OLA-3 EXHIBIT NO. GPC II-171B

In the matter of Georgia Power Co. et al., Vogtle Units 1 & 2

☐ Staff ☒ Applicant ☐ Intervenor ☐ Other

☒ Identified ☒ Received ☐ Rejected Reporter SD

Date 09-06-95 Witness Webb

92 PROJECT 057704

A. REQUIREMENT FOR REPORT

This event is reportable per.

a) 10 CFR50.73 (a)(2)(vii)(B), because a single event led to a system becoming inoperable which is designed to remove residual heat,
b) 10 CFR50.73 (a)(2)(ii), because an event resulted in the condition of the plant, including its principal safety barriers, being seriously degraded,
c) 10 CFR50.73 (a)(2)(iv), because an unplanned Engineered Safety Feature (ESF) actuation occurred when the ESF Actuation System Sequencer started.
d) Technical Specification 4.8.1.1.3, because a diesel generator failure occurred.

B. UNIT STATUS AT TIME OF EVENT

B.1 Power Level/Mode

Unit 1 was in Mode 6 (Refueling) at 0% rated thermal power. The reactor was shutdown on 2-23-90 for a 45 day scheduled re-fueling outage. The reactor core reload had been completed, the initial pass to tension the reactor vessel head studs was complete, and the outage team was waiting permission from the control room to begin the final tensioning. Reactor Coolant System (RCS) level was being maintained at mid-loop (187'-11") with Train A Residual Heat Removal (RHR) pump in service for decay heat removal. RCS temperature was being maintained at approximately 90 degrees F with indication from two connected incore thermocouples. The Emergency Boration Water Source was the Reactor Water Storage Tank (RWST). RWST level was at 79% (approx. 580,000 gallons) with a boron concentration of 2457 ppm. The Emergency Boration Flow Path was from the RWST through Train A Centrifugal Charging Pump (CCP) and the alternate charging flow path via valve 1HV-8147. Both Trains A and B Safety Injection (SI) breakers were capable of being racked in and the pumps operated in the hot leg injection mode if needed.

B.2 Inoperable Equipment/Abnormal System Alignment

Due to the refueling outage maintenance activities in progress, some equipment was out of service and several systems were in abnormal configurations.

92 PROJECT 057705

B

The Train B Diesel Generator (DG1A) was out of service for a required 36 month maintenance inspection. The Train B Reserve Auxiliary Transformer (RAT 1B) had been removed from service for an oil change. 1BA03, the Train B Class 1E 4160 Volt switchgear, was being powered from the Train A RAT (1A) through its alternate supply breaker. All Non-1E switchgear was being powered from the Unit Auxiliary Transformer (UAT). Procedure 13417-1, "Main and Unit Auxiliary Transformer Backfeed to the 13.8kV and 4160V Non-1E Busses" was used to establish power to Non-1E Busses 1NA01, 1NA04, and 1NA05.

The Train B CCP was removed from service for various corrective maintenance work orders (MWO's). The Chemical and Volume Control System (CVCS) letdown flowpath had been out of service for various maintenance activities and was being aligned for return to service.

The Accumulator #4 Isolation Valve (1HV-8808D) and the CVCS Normal Charging Check Valve (1-1208-U6-036), both located inside containment, were disassembled for repair. All Steam Generator (S/G) Nozzle Dams had been removed, but only S/G's #1 and #4 had their primary manways secured. Maintenance personnel were in the process of restoring the primary manways on S/G's #2 and #3. It was necessary to maintain the RCS level at mid-loop for the valve repairs and the S/G manway restorations. In addition, the pressurizer manway was removed to provide a RCS vent path.

C. DESCRIPTION OF EVENT

On March 20, 1990, at approximately 0817 CST, a truck driver and security escort entered the protected area driving a fuel truck. The driver's duties were to refuel air compressors and welding machines staged around the site for the outage on Unit 1. He had had these duties for the past three weeks. Since this vehicle was not a "designated vehicle", as defined by plant procedure, it does not remain in the protected area, and a security escort was provided for the truck.

The driver, who generally backs into the switchyard to fuel the machines in this area, pulled straight in. He checked the welding machine that was in the area, and found that it did not need fuel. He returned to the fuel truck and was in the process of backing when he hit a support holding "C" phase insulator for the RAT 1A. The insulator and line fell to the ground, causing a phase to ground fault, and the transformer tripped.

1B

At 0820CST, both RAT 1A and the Unit 2 ~~Train B~~ RAT Hi Side and Low Side breakers tripped causing a loss of offsite power condition (LOSP) to the Unit 1 Train A Class 1E 4160 volt Buss (1AA02), the Unit 2 Train B Class 1E Buss (2BA03), and the 480 volt busses supplied by 1AA02 and 2BA03. The Unit 1 Train B Class 1E 4160 volt buss (1BA03) also lost power since RAT 1A was feeding both Trains of Class 1E 4160 volt busses. RAT 1B was out of service for planned outage work. During this time, Non-1E busses for Unit 1 were energized through the 230 kV Switchyard to step- up transformers (step-down in this case) to the UAT to Non 1E busses 1NA01, 1NA04 and 1NA05. Unit 2 was in a normal electrical alignment. The ESF Actuation System Sequencers actuated upon LOSP and sent a start signal to Unit 1 and Unit 2 Diesel Generators.DG1A and DG2B started and sequenced the loads to their respective busses. Further description of the Unit 2 event is described in LER 50-425/1990-002.

One minute and twenty seconds after the DG1A engine started and sequenced the loads to the Class 1E bus, the engine tripped. ~~tripped.~~ This again caused an under voltage (UV) condition to class 1E bus 1AA02. The additional UV signal is a maintained signal at the sequencer. DG1A starting logic receives this signal and relays R-4A, TD2A and SOL-202-1A (activate shut-downs) energize. Since DG1A was coasting down from the trip, the shutdown logic did not allow the DG fuel racks or starting air solenoids to open and start the engine. This caused the engine starting logic to lock-up, a condition that existed until the UV signal was reset and relay TD2A deenergized. For this reason, DG1A did not re-start by itself after it tripped.

After the trip, operators were dispatched to the Engine Control Panel to investigate the cause of the trip. According to the operators, several annunciators were lit. Without fully evaluating the condition, the operators reset the annunciators. On the generator panel, the voltage balance relay was also found to be actuated. During this time, a Shift Supervisor (SS) and Plant Equipment Operator (PEO) went to the sequencer panel to find out if any problems were present on 1A sequencer. The SS quickly pushed the UV reset button. After pushing the reset button, the SS reset the sequencer by deenergizing and energizing the power supply to the sequencer. This caused the TD2A relay to deenergize and meet the permissive for starting air solenoid to energize for another 5 seconds which caused the engine to start. This happened 19 minutes after the DG tripped the first time. The engine started and the sequencer sequenced the loads as designed. After 1 minute and 10 seconds, the breaker and the engine tripped a second time. It did not start back due to the starting logic being blocked as described above. At this time, operators, a maintenance foreman and the diesel generator vendor representative were in the DG room. The initial report was that the jacket water pressure trip annunciators were the cause of the trip. The maintenance foreman and vendor representative observed that the jacket water pressure at the gauge was about 12-13 PSIG. The trip set point is 6 PSIG and the alarm setpoint is 8 PSIG. Also, the control room observed a lube oil sensor malfunction alarm.

Fifteen minutes after the second DG1A trip, DG1A was started from the engine control panel using the emergency start breakglass button. The engine started and loads were manually loaded. When the DG is started in emergency mode, all the trips except four are bypassed. However, all alarms will be annunciated. During the emergency run, no trip alarms were noticed by the personnel either at the control room or at the engine control panel. The only alarms noted by the control room operator assigned for DG run were lube oil pressure sensor malfunction and fuel oil level High/Low alarm.

DG1A ran until 1157 CST, supplying power to the 1AA02 4160 volt buss. At 1040 CST, RAT 1B had been energized to supply power to the 1BA03, 4160 volt, Class 1E Train B buss. At 1157 CST, the 1AA02 buss was tied to RAT 1B.

A Site Area Emergency was declared at 0840 CST, due to a loss of all off site and on site AC power for more than 15 minutes. The Emergency Director signed the notification form used to inform off site government agencies of the emergency at 0848 CST. The ENN Communicator then attempted to notify off site agencies using the primary ENN to Georgia and South Carolina. However, the primary ENN was inoperable due to the loss of power. The primary ENN receives power from A Train 1E buses which were de-energized due to the loss of electrical power event. The General Manager made an update to the notification form at 0856 CST to state that power had been restored at 0856 CST.

The ENN Communicator then went to the South Carolina backup ENN and established communications with South Carolina agencies (South Carolina Emergency Preparedness Division (EPD), Savannah River Site (SRS), Aiken, Allendale and Barnwell Counties) at approximately 0858 CST. Initial notification of the emergency to these agencies was completed at approximately 0910 CST. The Georgia Emergency Management Agency (GEMA) was contacted via commercial telephone, which is the designated backup to GEMA and Burke County EMA, at approximately 0915 CST. However, no notification message was transmitted during this contact, because of communication confusion.

At the time the Control Room ENN communicator contacted GEMA on the commercial telephone, the Tecnical Support Center (TSC) ENN Communicator was confirming the operability of the primary ENN to Georgia and South Carolina. The ENN in the TSC was operable because it received power from the Security Diesel, which was operating properly. The commercial telephone contact between the control room and GEMA was terminated because both parties assumed the notification would be transmitted via the ENN. In fact, the TSC ENN Communicator did not have the notification forms and could not pass the required information. Attempts by GEMA to obtain the notification form information were successful at 0935 CST when South Carolina Emergency Preparedness Division (EPD) sent GEMA the notification form via facsimile. Plant Vogtle established communications with CLMA at 0940 CST and passed the notification information successfully via commercial telephone lines. Subsequent notifications were made without difficulty.

The initial notification to the NRC was made at 0858 CST by the Control Room on the ENS. Subsequent updates from the Control Room and TSC were performed without major problem except for a hardware problem on the NRC end which caused them to drop off the line occasionally.

The primary means of notifying on-site personnel is via the plant public address system (plant page) for personnel in the protected area and outside the protected area but in the owner controlled area. In general, these notifications were made successfully with a few minor exceptions.

The plant page announcement of the site area emergency was made at 0901 CST. It was heard in all of the protected area except inside containment, on the turbine deck of the turbine building, and in the diesel building. Personnel in these areas were notified by informal means (word of mouth, supervisors, observing others leaving area, etc.) within approximately 10 minutes of the page announcement. Personnel in buildings outside the protected area were notified by telephone calls from security by 0917 CST.

The delay in making the plant page announcement, from emergency declaration at 0840 to page announcement at 0901, caused emergency facility activation to be delayed approximately 21 minutes.

The plant was at mid-loop when the event occurred. Several work orders were in progress at that time. Instructions were given by the Emergency Director to complete the following tasks prior to leaving containment:

a) 1HV-8808D reassembly and bonnet bolts tightened. This is the SI Accumulator #4 isolation valve.

b) Complete installation of Steam Generators #2 and #3 manways.

c) Close the equipment hatch and reinstall the interlocks on the personnel air lock.

All work was accomplished and maintenance personnel exited containment by 1050 CST.

The supply breakers for Class 1E busses 1AA02 and 1BA03 were moved so that RAT 1B could supply power.

This Still needs to be moved

92 PROJECT 057709

The announcement of the emergency advised that a Site Area Emergency had been declared and that all visitors and escorts should report to the Plant Entry Security Building (PESB); and all emergency response personnel should report to their emergency response facility. The prescribed section of the initial announcement from the emergency procedure concerning evacuation and assembly was purposely omitted. Therefore, neither a total site evacuation nor a complete assembly and accountability were initiated. The decision to omit this section by the Emergency Director was based on there not being any immediate radiological danger to the plant personnel. The omission of the evacuation and assembly announcement caused confusion on the plant site because there were no instructions for non-essential personnel. Some personnel stayed at their work location, some personnel exited the protected area and assembled in the Administration Building and parking lot area for accountability, and approximately 200 personnel relocated to a relocation center located about 1 mile from the plant.

Another public address system announcement was made at approximately 0917 CST stating that the emergency had been downgraded to an "Alert" status and that all non-essential personnel were to assemble at the Administration Building parking lot for accountability. Some personnel already located in the Administration parking lot area did not hear this announcement due to public address system inaudibility. Therefore, no additional information was received by these people. Many personnel considered themselves essential, and therefore, re-entered the plant protected area.

News media releases were made out of the Georgia Power Company corporate office in Atlanta, Ga. with information supplied by the Southern Nuclear Operating Company (SONOPCO) Project office in Birmingham, Alabama. The process that SONOPCO uses to release information to the media is as follows:

> The SONOPCO public affairs (PA) personnel are notified upon activation of the General Office Operations Center (GOOC) by the GOOC Manager. Upon notification, they report to the GOOC.
>
> The GOOC Manager assists public affairs personnel by providing plant status information coupled with technical assistance as the PA personnel prepare draft press releases.
>
> The press releases are then approved by the Project Vice President or Corporate Duty Manager and transmitted to the Georgia Power Supervisor of Public Relations in Atlanta by telecopy. The Supervisor of Public Relations then transmits the press release to the site Public Relations Supervisor and to media personnel.

Plant status to the GOOC was hampered by failure of the telephone bidge status loop to work properly. GOOC personnel established communications with the TSC thru a separate phone line to obtain plant status.

The first press release contained two errors. The first error was in the time of declaration of the Site Area Emergency. This occurred when the General Manager called the Project Vice President and indicated that a site area emergency had been declared. This was the first indication for corporate personnel that a site area emergency had been declared and the time of the call was approximately 0900 CST. Previous notification by the site duty manager to the corporate duty manager did not indicate that activation of the emergency plan had occurred at 0840 CST. GOOC personnel assumed the Site Area Emergency had been declared at 0900 CST. The second error stated that "non-essential personnel were evacuated" and should have stated that non-essential personnel were evacuated from the protected area to accomplish site accountability. This error resulted from a mis-communication between the plant and GOOC personnel. The second press release contained only the time error. No further press releases were needed due to the press conference held that afternoon in the Atlanta corporate office.

By 1200 CST, plant conditions had stabilized with off site power restored to Unit 1 and RHR established for core cooling. The Emergency Director initiated a conference call with local government agencies (South Carolina, Georgia, Allendale, Barnwell, Burke County and SRS) to discuss termination of the emergency. The Emergency Director also discussed termination with the NRC. Agreement was reached with all parties that the emergency would be terminated. The emergency was terminated at 1247 CST and all agencies were notified by 1256 CST.

3. CAUSE OF EVENT

3.1 Direct Causes

a) The direct cause of the loss of off-site class 1E AC power was the fuel truck hitting a pole supporting a 230kV line for RAT 1A, which caused the loss of the off-site power source.

b) The direct cause of the loss of on-site class 1E power was the failure of the operable DG, DG1A, to start and load the LOSP loads on bus 1AA02.

3.2 Root Causes

a) The truck driver met all current site training and qualification requirements, including holding a Class 2 Georgia driver's license. However, to drive the same truck on state highways would have required a Class 4 license. The site requirement was therefore, inadequate. Furthermore, site safety rules require a flagman for backing vehicles when viewing is impaired, as was the case on 3-20-90. This rule was violated.

b) The root cause for the failure of DG1A has not been conclusively determined. The two trips that occurred during this event occurred at 1 minute 20 seconds and 1 minute 10 seconds after the DG tied to the bus. There is no record of the trips that were annunciated after the first trip. The cause of the first trip can therefore only be postulated, but most likely has the same root cause as the second trip.

The second trip occurred at the end of the timed sequence of the group 2 block logic. This logic provides for the DG to come up to operating conditions before the trips become active. The block logic timed out and the trip occurred at about 70 seconds. The annunciators observed at the second trip included jacket water high temperature along with other active trips. It is believed that the jacket water trip is the most likely cause of the second trip. In conducting an event review team's test plan, the trip conditions that were observed on the second DG trip on 3/20/90 were essentially recreated by venting 2 out of 3 temperature sensors, simulating a tripped condition. The recreation duplicated both the annunciators and the 70 second trip time. This most likely cause assumes an intermittent actuation of jacket water temperature switches.

During bench testing, all three jacket water temperature switcheswere found to be set high during the DG maintenance inspection in early March 1990 (by approximately 6-10 degrees F above the setpoint). All three were adjusted downward using a calibration technique that may have differed from that previously used.

Following the 3-20-90 event, all three switches were again bench tested. Switch TS-19110 was found to have a setpoint of 197 degrees F, which was approximately 6 degrees below its previous setting. Switch TS-19111 was found to have a setpoint of 199 degrees F, which was approximately the same as the original setting. Switch TS-19112 was found to have a setpoint of 186 degrees F, which was approximately 17 degrees F below the previous setting and was re-adjusted. Switch TS-19112 also had a small leak which was judged to be acceptable to support diagnostic engine tests and was reinstalled.

During the subsequent test run of the DG on 3-30-90, one of the switches (TS-19111) tripped and would not reset. This appeared to be an intermittent failure because it subsequently reset. This switch and the leaking switch (TS-19112) were replaced with new switches. All subsequent testing was conducted with no additional problems.

The jacket water temperature switches were recalibrated with the manufacturer's assistance to ensure a consistent calibration technique.

Subsequent testing indicated that the diesel annunciator indication of 3-20-90 is reproduced on a high jacket water temperature trip.

A test of the jacket water system temperature transient during engine starts was conducted. The purpose of this test was to determine the actual jacket water temperature at the switch locations with the engine in a normal standby lineup, and then followed by a series of starts without air rolling the engine to replicate the starts of 3-20-90. The test showed that jacket water temperature at the switch location decreased from a standby temperature of 163 degrees F to approximately 156 degrees F and remained steady.

Numerous sensor calibrations (including jacket water temperatures), special pneumatic leak testing, and multiple engine starts and runs were performed under various conditions. Since 3-20-90, DG1A has been started 18 times, and DG1B has been started 19 times. No failures or problems have occurred during any of these starts. In addition, an undervoltage start test without air roll was conducted on 4-6-90 and DG1A started and loaded properly.

Based on the above facts, we have concluded that the jacket water high temperature switches were the most probable cause of both trips on 3-20-90.

3.3 Contributing Causes

c) Plant conditions were inadequate prior to the event. Two of four sources of class 1E AC power were not enough to ensure plant protection in light of the event which actually occurred. Procedures did not sufficiently address loss of RHR during outage conditions or rapid closing of containment and RCS openings during outage conditions.

d) The flow of information to the GOOC was inadequate due to loss of the telephone bridge lines. Information was not easily verifiable and this led to the inaccuracies in the press releases.

e) Off-site notifications were inadequate. Georgia agencies were not a part of the back-up ENN because in 1986 the back-up ENN was replaced before it was put into use at P'ant Vogtle. A decision was made at that time that since a back-up was not required that it was not necessary to add the two Georgia agencies since they could be notified by commercial phone lines if the primary ENN failed. Thus, the commercial phone lines were the back-up notification system for the two Georgia agencies at the time of this event. The Emergency Director did not emphasize the importance of prompt off-site communications and did not ensure ongoing communications with outside agencies. Additionally, the Control Room communicators did not initially understand the funtioning of the back-up and alternate systems.

f) The Emergency Response Facility (ERF) computer did not provide accurate historical data to personnel in the TSC, Operations Support Center (OSC) and Emergency Operations Center (EOF) because of a component failure of its data concentrator.

g) Accountability of non-essential personnel was not properly conducted because an evacuation was not ordered and there was no clear-cut understanding of who was or was not essential. The Emergency Plan implementation was inefficient in that the Emergency Director did not see that clear and explicit directions were given when deviating from Emergency Plan procedures by not ordering an evacuation when the Site Area Emergency was declared.

4. ANALYSIS OF EVENT

Unit 1 was in Mode 6 aproximately 25 days into refueling, with safety related Train "A" providing decay heat removal. The primary system was at approximately mid-loop and steam generator primary manways were being installed. The loss of offsite power to the Class 1E buss 1BA03 and failure of DG1A to start and operate successfully, coupled with DG1B and RAT 1B being out of service for maintenance, resulted in Unit 1 being without AC power to both Class 1E busses. With both Class 1E busses de-energized, the Residual Heat Removal (RHR) System could not perform its required safety function.

DG1A was manually started within approximately 36 minutes, after two trips, and Train "A" RHR, Component Cooling Water (CCW), and Nuclear Service Cooling Water (NSCW) were re-established. Based on a noted rate of rise in the RCS temperature of 16 degrees F, measured at the core exit thermocouples over a fifteen minute period, the RCS water would not have been expected to begin boiling until approximately 1 hour and 50 minutes after the beginning of the event. Based on this RCS water temperature and a review of expected results of a loss of RHR flow, the fuel and equipment is expected to have remained well within design limits.

The steam generator primary side manway installation and closure of the containment equipment hatch were completed after re-establishing RHR, both well within the estimated 1 hour 50 minutes prior to the projected onset of boiling in the RCS. A review of information obtained from the Process and Effluent Radiation Monitoring System (PERMS) and grab sample analysis indicated all normal values. As a result of this event, no significant increase in radioactive releases to either the containment or the environment occurred.

Additional systems were either available or could have been made available to ensure the continued safe operation of the plant:

1. The maintenance on RAT 1B was completed and the RAT returned to service approximately 2 hours into the event.

2. Offsite power was available to Non-1E equipment through the generator step-up transformers which were being used to "back-feed" the Unit Auxiliary Transformers (UAT) and supply the Non-1E busses. Class 1E busses 1AA02 and 1BA03 could have been powered by feeding through Non-1E bus 1NA01.

3. The Refueling Water Storage Tank could have been used to manually establish gravity feed through the RHR and/or Chemical and Volume Control System (CVCS), and Safety Injection (SI) to the RCS to maintain a supply of cooling water to the reactor.

Consequently, neither plant safety nor the health and safety of the public was adversely affected by this event.

A more detailed assessment of this event and an assessment of potentially more severe circumstances will be performed and included in a supplemental LER.

F. CORRECTIVE ACTIONS

a)

1)Onsite truck driver license requirements will be changed to match state requirements by 2001.

2)Security officers' escort training will be changed by 8-1-90 to emphasize safe operation of vehicles.

3)Sensitive and vulnerable areas inside the the protected area will be evaluated by 2001 and appropriate barriers erected or controls established.

4)An engineering review of insulator support structures will be conducted by 2001 and changes made, as necessary.

b)

1)Personnel will evaluate the replacement of the currently installed diesel sensors switches with a more reliable design by 2001.

2)The Loss of Off Site Power (LOSP) diesel start and trip logic has been modified so that an automatic emergency start will occur upon LOSP.

3)DG operating procedures will be revised to include restarts following a DG trip during LOSP by 7-1-90.

4)A review of the storage, handling and installation of diesel logic boards is being conducted to improve logic board reliability and will be completed by 2001.

5)Operator guidance on recording pertinent alarms and indications is being developed in order to assist in investigations of future plant events and will be in place by 5-1-90.

6)~~When DG1A is declared operable,~~ the test frequency for DG 1A will be increased to once every 7 days in accordance with Technical Specification Table 4.8-1. This frequency will be continued until 7 consecutive valid tests are completed and and one or less valid failures have occurred in the last 20 valid tests. Including these two valid failures, there have been a total of four valid failures in 66 valid tests of DG1A.

c)

1)A review of the sequence of refueling outage maintenance activities is being conducted and will be completed by 2001. This includes plant electrical line-ups, and RCS and containment integrity with regard to mid-loop operations and Generic Letter 88-17.

2)The procedure governing a loss of RHR condition will be revised by 2001 to include actions to be taken during outage situations.

3)Procedural controls will be established by 2001 to ensure that containment and RCS openings can be expeditiously closed within required time frames.

d)

1)A means for providing battery power to the telephone bridge is being studied with plans to be implemented by 2001.

2)By 7-9-90, GOOC personnel will implement methods for verifying the accuracy of site information prior to its public release.

e)

1)GEMA and Burke County EMA have been added to the back-up ENN.

2)Battery back-up power will be added to the primary ENN by 2001.

3)Additional training will be provided to Control Room communicators and supervisors on the capabilities of the communication system used for off-site notifications by 9-15-90.

4)By 2001, Emergency Director training will emphasize the importance of prompt accurate reports to off-site agencies.

f)

1)The ERF data concentrator has been replaced and the Emergency Planning staff will begin conducting regular operability tests by 6-15-90, for the ERF computer system in the TSC and EOF.

g)

1)Actual assembly and accountability drills will be conducted by 2001, and the definitions of essential and non-essential will be better defined in General Employee Training.

2)Training for Emergency Directors and ERF Managers will emphasize, by 2001, that deviation from procedures may cause confusion and that clear instructions must be provided for any deviations.

G. ADDITIONAL INFORMATION

1. Failed Components:

ERF data concentrator

2. Previous Similar Events:

None

3. Energy Industry Identification System Code:

Reactor Coolant System - AB
Administration Building - MA
Residual Heat Removal System - BP
Diesel Generator Lube Oil System - LA
Diesel Generator Starting Air System - LC
Diesel Generator Cooling Water System - LB
Diesel Generator Power Supply System - EK
Safety Injection System - BQ
13.8 kV Power System - EA
4160 volt non-1E power system - EA
4160 volt Class 1E power system - EB
Chemical and Volume Control System - CB
Containment Building - NH
480 volt Class 1E Power System - ED
Engineered Safety Features Actuation System - JE
Plant Page System - FI
Security System - IA
Component Cooling Water System - CC
Nuclear Service Cooling Water System - BS
Radiation Monitoring System - IL