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

Report No.: 50-395/91-24

Licensee: South Carolina Electric & Gas Company
Columbia, SC 29218

Docket No.: 50-395 License No.: NPF-12

Facility Name: V. C. Summer Nuclear Station

Inspection Conducted: December 18, 1991 through January 31, 1992

Inspector: FOR R.W. Wright 2/13/92
R. C. Haag, Senior Resident Inspector Date Signed

Inspector: FOR R.W. Wright 2/13/92
L. A. Keller, Resident Inspector Date Signed

Approved by: Floyd S. Cantrell 2/14/92
Floyd S. Cantrell, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine inspection was conducted by the resident inspectors onsite in the areas of monthly surveillance observations, monthly maintenance observations, operational safety verification, ESF system walkdown, onsite follow-up of written reports of nonroutine events at power reactor facilities, and onsite follow-up of events at operating power reactors. Selected tours were conducted on backshift or weekends. Backshift or weekend tours were conducted on eight occasions.

Results:

The plant operated at 100 percent power throughout the inspection period with the exception of a planned shutdown on December 27-29, 1991, to allow plugging of leaking tubes in all four turbine generator hydrogen coolers. Beginning on December 19, 1991 and throughout the rest of the inspection period, there were indications of elevated reactor coolant activity associated with minor fuel failure (paragraph 7). Axial offset limits were reduced to compensate for increasing values of measured hot channel factors (paragraph 2). A concern was identified with licensee corrective action in that a procedure change was not timely enough to prevent recurrence (paragraph 2). There continue to be uncontrolled operator aids identified by the inspectors (paragraph 2). A non-cited violation was identified for failure of operators to comply with TS

for containment isolation valves (paragraph 2). An unresolved item was identified for inadequate corrective action, for failure to adequately disposition safety-related circuit breaker failures (paragraph 3). A non-cited violation for failure to properly tagout the "A" EDG was identified (paragraph 3). A review of the lubrication program identified a weakness in the storage of lubricants for use by operators. Consideration had not been given to the shelf life of these lubricants.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*F. Bacon, Acting Manager, Chemistry and Health Physics
K. Beale, Supervisor, Emergency Services
*C. Bowman, Manager, Maintenance Services
*M. B[illegible]ne, Manager, Design Engineering
*B. Christiansen, Manager, Technical Services
H. Donnelly, Senior Engineer, Nuclear Licensing
S. Furstenberg, Associate Manager, Operations
D. Haile, Engineer, Nuclear Licensing
*W. Higgins, Supervisor, Regulatory Compliance
*S. Hunt, Acting General Manager, Nuclear Safety
*A. Koon, Manager, Nuclear Licensing
*K. Nettles, General Manager, Station Support
*H. O'Quinn, Manager, Nuclear Protection Services
*C. Osier, Acting Manager, Systems & Performance Engineering
C. Price, Manager, Technical Oversight
*M. Quinton, General Manager, Engineering Services
*J. Skolds, Vice President, Nuclear Operations
*G. Soult, General Manager, Nuclear Plant Operations
G. Taylor, Manager, Operations
*A. Torres, Associate Manager, Quality Control
K. Woodward, Manager, Nuclear Operations Education and Training

Other licensee employees contacted included engineers, technicians, operators, mechanics, security force members, and office personnel.

*Attended exit interview

Acronyms and initialisms used throughout this report are listed in the last paragraph.

S. C. Flanders, Reactor Engineer Intern, Project Directorate IV-2, NRR, was onsite January 6-17, 1992 for training.

A regional inspection in the area of motor-operated valves was performed January 27-31, 1992.

A regional inspection in the area of emergency preparedness was performed January 27-31, 1992.

G. Wunder, Project Manager, NRR, was onsite January 30, 1992, to meet with the resident inspectors, licensee management and review the MOV inspection findings.

2. Monthly Surveillance Observation (61726)

The inspectors observed surveillance activities of safety-related systems and components listed below to ascertain that these activities were conducted in accordance with license requirements. The inspectors verified that required administrative approvals were obtained prior to initiating the test, testing was accomplished by qualified personnel in accordance with an approved test procedure, test instrumentation was calibrated, and limiting conditions for operation were met. Upon completion of the test, the inspectors verified that test results conformed with technical specifications and procedure requirements, any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel, and the systems were properly returned to service. Specifically, the inspectors witnessed/reviewed portions of the following test activities:

* Operation of the nuclear sample system under normal conditions (CP 903). The inspector observed a RCS sample drawn utilizing the post accident sample system (PASS). The sample was drawn to support determination of dose equivalent iodine per CP 303. The technician was very knowledgeable of the sample system. The sample was taken in accordance with the approved procedure and no discrepancies were noted.

* Reactor core flux mapping (STP 212.001). A full core flux map was taken in order to obtain data for Heat Flux Hot Channel Factor ($F_Q(z)$) determinations.

* Heat flux hot channel factor ($F_Q(z)$) determination (STP 204.001). The purpose of this procedure is to verify through analysis of reactor core flux mapping data, that $F_Q(z)$ is within the limits specified in TS 3.2.2. This procedure is normally performed once every 31 effective full power days (EFPDs). However, with the maximum value of $F_Q M(z)/K(z)$[1] over the core height (z) increasing since the previous determination of $F_Q M(z)$, this procedure is required to be performed at least once per 7 EFPDs until two successive flux maps indicate that the above relationship is not increasing. The tenth flux map this cycle indicated that $F_Q M(z)/K(z)$ increased relative to the ninth flux map. Accordingly, the frequency of this surveillance was increased to at least once every 7 EFPDs. Additionally, TS 4.2.2.2C. places limits on $F_Q M(z)$ for relaxed axial offset control (RAOC) operation. This limit is more restrictive due to a cycle dependent function [W(z)] which is factored into the limit calculation to account for power distribution transients encountered during normal operation. The tenth flux map indicated that this RAOC limit was exceeded by 2.23 percent. This required reducing axial flux difference (AFD) limits by 2.23 percent per TS 4.2.2.2.f.2.A.

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1 $F_Q M(z)$ is the measured heat flux hot channel factor as a function of core height. K(z) is the normalized $F_Q(z)$ as a function of core height.

The subsequent flux map (eleventh) indicated that $F_Q M(z)/K(z)$ decreased relative to the tenth flux map and the RAOC FQ limit was exceeded by a lesser amount (2.01 percent versus 2.23). The twelfth flux map showed an increase in $F_Q M(z)/K(z)$ relative to the eleventh flux map, necessitating continued flux maps every 7 days. The next two successive flux maps indicated that $F_Q M(z)/K(z)$ was decreasing, allowing the licensee to go back to performing flux maps every 31 EFPDs.

* Seismic monitoring system triaxial response - spectrum recorders calibration (STP 391.005). NRC Inspection Report 91-23 identified a non-cited violation (NCV 395/91-23-01) for failure to adequately maintain STP 391.005. The licensee had failed to incorporate the latest vendor guidance for frequency calibration acceptance criteria. As a result, licensee management directed that STP 391.005 be changed to reflect the revised acceptance criteria. However, the procedure change was not made in a timely manner, which resulted in one of the recorders being calibrated and returned to the field with one of it's reeds exceeding the acceptance criteria. The I&C supervisor responsible for reviewing the paperwork for this job recalled that the acceptance criteria was supposed to be changed. The recorder was then recalibrated to meet the new acceptance criteria. Having to re-perform the calibration resulted in the recorder being out of service an additional three days. While this error did not result in exceeding the 30 day time limit under the TS action statement, it does indicate that greater attention to detail is needed for correction of identified problems.

* Monthly surveillance test of "B" chill water pump (STP 229.001).

* Engineered Safety Feature (ESF) slave relay test for train "B" (STP 345.077). The purpose of this procedure is to functionally verify the operability of the "B" train ESF actuation system slave relays. The test was satisfactorily performed. However, while observing the test, the inspector noted a handwritten piece of paper taped on the inside of the safeguards test cabinet (XPN 7021). The information on the paper listed equipment indicating lights in the cabinet and their corresponding fuse number and fuse location. These fuses listed are located in the solid state protection system (SSPS). This paper was of indeterminate age and was apparently not being controlled. The inspector informed the I&C supervisor, who subsequently removed the paper. The I&C supervisor did not know the purpose of the posted paper and stated that I&C personnel would not have utilized this paper. The inspectors have previously identified uncontrolled operator aids in the plant. The licensee stated that they have conducted a walkdown of the plant to identify and remove any unauthorized operator aids, but that the inside of cabinets were not part of the walkdown. The inspectors suggested to the licensee that maintenance and operations personnel be made aware of the need

to identify and remove any additional operator aids in the plant, including the inside of cabinets.

* Stroke testing the outside containment isolation valve XVA 9312B in the containment air sampling return line (STP 105.015). This test involved closing this normally open valve from the safeguards slave relay. However when the close signal was provided, the valve did not fully close. The valve stopped in a mid position as indicated by the main control board (MCB) lights. Later the operators were able to close the valve using the control switch on the MCB.

During the intergrated safeguards testing performed in the last refueling outage (November 1991), XVA 9312B also failed to fully close. This occurred on four separate occasions during safeguards testing. While troubleshooting the problem, the valve was observed to operate properly from the MCB switch, therefore no repair work was performed. Retests consisted of stroking the valve using the MCB switch. The stroke test on January 27, 1991, was the first time the valve had been cycled since the retest associated with the intergrated safeguards test.

Since the valve would not fully close via the slave relay, it was declared inoperable and the action statement of TS 3.6.4 was entered. To comply with the TS, the licensee closed and de-activated one automatic valve in the affected penetration. With the penetration isolated the licensee also entered the action statement for TS 3.4.6.1 since the reactor building atmosphere particulate radioactivity monitoring system would also be isolated. The TS action statement required analysis of a containment atmosphere grab sample every 24 hours. Initially, to comply with the TS both valves in the affected penetration were opened and the sample was obtained and analyzed by the normal radiation process monitor. The process time was approximately 30 minutes in which both penetration valves were opened. This method of sampling was performed on three occasions.

Operations subsequently questioned the rationale of opening a valve that had been earlier closed and de-energized to comply with TS. The inspector also questioned this practice after it was discovered that both valves in the penetration were being opened to obtain air samples. The earlier basis for opening the valve was Station Administrative Procedure (SAP) 205, which allows temporary restoration of equipment to service in order to troubleshoot or repair the inoperable condition. The inspector does not consider the opening of the valve to obtain an air sample as meeting the intent of SAP 205. Nor does TS 3.6.4 allow opening of a valve after it is closed and de-activated, until the inoperable condition which required entry into the TS LCO has been corrected. After conversation with the licensee, it appears they are in agreement with this view of TS 3.6.4. This licensee identified violation NCV

395/91-24-01 for failure to comply with TS 3.6.4 is not being cited because criteria specified in section V.A of the NRC Enforcement Policy were satisfied.

At the end of the inspection period, the licensee had not determined the cause of XVA 9312B not fully closing when activated from the slave relay. Subsequent testing/stroking provided varied results. On a few occasions the valve did not fully close while on other occasions it cycled satisfactorily. The licensee is continuing to investigate this problem. The inspector will followup on the licensee's efforts to resolve this problem and any additional action taken to ensure SAP 205 is properly implemented. Also, the inspector will review the previous corrective action following the intergrated safeguard test which did not completely address the identified deficiency nor prevent recurrence.

A non-cited violation of Technical Specifications was identified for operator actions in response to a valve failure identified during surveillance testing. This violation was identified by operations personnel. A lack of aggressive followup action by the licensee was noted for correction of a deficient procedure and for removal of uncontrolled operator aids.

3. Monthly Maintenance Observation (62703)

Station maintenance activities for the safety-related systems and components listed below were observed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, and industry codes or standards and in conformance with TS.

The following items were considered during this review: that limiting conditions for operation were met while components or systems were removed from service, approvals were obtained prior to initiating the work, activities were accomplished using approved procedures and were inspected as applicable, functional testing and/or calibrations were performed prior to returning components or systems to service, quality control records were maintained, activities were accomplished by qualified personnel, parts and materials used were properly certified, and radiological and fire prevention controls were implemented. Work requests were reviewed to determine the status of outstanding jobs and to ensure that priority was assigned to safety-related equipment maintenance that may affect system performance. The following maintenance activities were observed:

* Replacement of the "A" emergency diesel generator supply header service water expansion joint XEJ 004A (MWR 91M0353). This expansion joint was replaced due to corrosion on the protective cover. After observing the work, the inspector identified that the danger tag which required opening of the supply header vent valve (IPX 4476A) had been incorrectly placed on the discharge header vent valve

(IPX 44768). Independent second person verification associated with valve alignment for the danger tag did not detect the error. This resulted in the discharge header vent valve being opened rather than the intended supply side vent valve. While the safety significance of this event for both personnel safety and equipment availability was low, the inspectors were concerned with the event since it involved a failure of the independent verification program and occurred with the danger tagging system.

An Off-Normal Occurrence (ONO 92-001) was written to document the tagout discrepancy. In dispositioning the ONO, a licensee management review board concluded that the discrepancy was due to personnel error on the part of the person ha ng the tag and the person responsible for verification. The people involved attributed their error to inattention to detail nd rushing through the tagout due to a busy shift schedule. The corrective action included a verbal reprimand and increased training for the two people involved in the error, and a lessons learned briefing for other operators. The inspector noted that licensee management considered the event serious and that the corrective action taken appeared adequate.

Failure to properly tagout equipment could result in equipment damage or personnel injury, and is a violation of procedure. The failure to follow procedures for equipment control (e.g., danger tagging), as required by TS 6.8.1.a is a violation. This NRC identified violation NCV 395/91-24-02 for failure to follow procedure is not being cited because the criteria specified in section V.A of the NRC Enforcement Policy were satisfied.

* Annual internal inspection of critical measurements for component cooling water booster pump "A" (PMTS P0152054). Inspector verified proper tagout of equipment, appropriate procedures were utilized, and measurement devices were calibrated. All measurements indicated clearances were within tolerance.

* Annual internal inspection of critical measurements for service water screen wash pump "B" (PMTS P0149094). Inspector verified proper tagout of equipment, appropriate procedures were utilized, and measurement devices were calibrated. All measurements indicated clearances were within tolerance.

* Inspection of recycle holdup tanks (XTK 06 A/B) diaphragms (MWRs 92M3004/5). Both recycle holdup tanks (RHTs) have a diaphragm located above the stored fluid. The diaphragm prevents air from dissolving into the reactor coolant and prevents reactor coolant gases from escaping into the auxiliary building atmosphere. The inspector and licensee personnel inspected the tank diaphragms and they appeared to be intact. However, XTK 06A had a small amount of fluid on top of the diaphragm and what may have been boron crystals around this fluid. The licensee has a spare diaphragm onsite and

indicated that the diaphragm in XTK 06A will be replaced in late February, 1992, and the diaphragm in XTK 06B shortly thereafter. The inspector was informed that this was the first time these diaphragms had been inspected since construction.

* Installation of a freeze seal on the service water piping to provide isolation for the bypass piping modification. The inspector reviewed maintenance procedure MMP 105.001, "Freeze Seals for Stainless Steel and Carbon Steel Pipe", and verified that both personnel safety and plant equipment safety considerations were adequately addressed. The licensee was successful in minimizing the time required to maintain the freeze seal since one train of chill water was inoperable during this time period.

* Calibration of meters on the local control panel for "A" emergency diesel ge rator (PMTS P0150505).

* Semi-annual instrument loop calibration for component cooling water heat exchanger service water flow transmitter IFT 4490 (PMTS P0151449). Also included in the work was the flushing of the sensing lines to the transmitter to prevent any buildup of foreign material and potential blockage of the sensing lines.

* Annual calibration and film replacement for seismic strong motion acceler(jraph, IYM 1793A (PMTS P0151057).

* Inspection of reservoir fluid level for the dashpot of the service water booster pump discharge check valve XVC 3135B (MWR 91T0346). The dashpot is connected to the disc to provide dampening of valve movement. During a previous inspection of the discharge check valve for "A" SW booster pump, the reservoir level was low and the stroke time differed from the procedural guidelines. For XVC 3135B the oil level was acceptable and only an ounce of oil was added. Also, the inspector was informed that the procedural guidance for valve stroke time would be updated to reflect actual valve parameters.

* Replacement of the service water pump house supply fan breaker (PMTS P0148712). The inspector observed the installation of a new feeder breaker (XMC1EAIX 01FH) for the service water pump house supply fan (XFN 0080A-AH). This is a safety-related, class 1E molded case circuit breaker. The inspector learned that the original breaker had failed it's overcurrent trip test (EMP 280.004). This test consisted of placing the breaker on the test stand and applying short pulses of current to one phase of the breaker, and increasing the current on each succeeding pulse until the breaker trips. This was done for all three phases. The breaker exceeded the maximum trip point tolerance on two of the three phases, and did not trip at all on the third phase. The inspector was concerned with this type of failure due to

the potential to lose the entire motor control center from a single fault.

The inspector later inquired about the status of the evaluation for this failure, and was informed that it was the licensee's policy to replace molded case circuit breakers that have failed without evaluation as to the cause of the failure. This is accomplished by utilization of a pre-approved disposition (PAD 12), which is a standard engineering services disposition for expected type failures due to normal wear or aging. Other examples of deficiencies which are handled under PAD 12 include valve packing replacement, general cleaning of equipment, gasket replacement, etc. When applying a PAD-12 disposition, the licensee does not evaluate for root cause, 10 CFR 50.72/73 or 10 CFR 21 reportability, or for possible generic concerns. The inspector was concerned that by utilizing PAD-12 these required evaluations were not being performed, and that a circuit breaker failure which rendered the breaker unable to perform it's safety function was classified as "expected". Furthermore, the licensee stated that the policy for utilizing PAD-12 applied regardless of the breaker application or age.

The inspector reviewed the licensee's records for circuit breaker failures from January, 1989 until January, 1992. For this time period, the inspector found 15 examples of safety-related circuit breaker failures which were handled under PAD-12 and therefore were not evaluated for cause, reportability, etc. The lack of an evaluation for the cause of the circuit breaker failures mentioned above has been identified as Unresolved Item (91-24-03).

These failures were included in the licensee's class 1E equipment semi-annual failure trend report, which lists the number of breaker failures but does not categorize the failure or identify the cause. The licensee stated that based on this report, there is not an adverse trend in the number of breaker failures; and that considering the large number of breakers in the plant and the number of molded case circuit breaker tests per year, they did not feel that 15 failures over a three year period represented a generic problem.

An unresolved item was identified for failure to evaluate the cause of 15 safety-related circuit breaker failures that occurred between January, 1989 and January 1992. This item will be examined further by the EDSFI team scheduled for March 1992. A non-cited violation for failure to properly tagout the "A" EDG was identified. All other maintenance activities observed were completed using the required procedures and equipment, and achieved the desired results.

4. Operational Safety Verification (71707)

a. Plant Tours and Observations

The inspectors conducted daily inspections in the following areas: control room staffing, access, and operator behavior; operator adherence to approved procedures, TS, and limiting conditions for operations; examination of panels containing instrumentation and other reactor protection system elements to determine that required channels are operable; and review of control room operator logs, operating orders, plant deviation reports, tagout logs, jumper logs, and tags on components to verify compliance with approved procedures.

The inspectors conducted weekly inspections in the following areas: verification of operability of selected ESF systems by valve alignment, breaker positions, condition of equipment or component(s), and operability of instrumentation and support items essential to system actuation or performance.

Plant tours included observation of general plant/equipment conditions, fire protection and preventative measures, control of activities in progress, radiation protection controls, physical security controls, plant housekeeping conditions/cleanliness, and missile hazards.

The inspectors conducted biweekly inspections in the following areas: verification review and walkdown of safety-related tagout(s) in effect; observation of control room shift turnover; review of implementation of the plant problem identification system; and verification of selected portions of containment isolation lineup(s).

Selected tours were conducted on backshifts or weekends. Inspections included areas in the cable vaults, vital battery rooms, safeguards areas, emergency switchgear rooms, diesel generator rooms, control room, auxiliary building, cable penetration areas, service water intake structure, and other general plant areas. Reactor coolant system leak rates were reviewed to ensure that detected or suspected leakage from the system was recorded, investigated, and evaluated; and that appropriate actions were taken, if required. On a regular basis, RWP's were reviewed and specific work activities were monitored to assure they were being conducted per the RWP's.

During a tour of the west penetration room, elevation 412, the inspector noted that a large number of lights were not lit. Approximately one half (fifteen) of the total number of lights in the room were effected. Due to the large number of lights, the inspector questioned if a power supply breaker could be the cause of the problem. The inspector was later informed that individual light bulb or socket failures caused the lights to be out. The inspector questioned the attention to detail by personnel making tours in the

room which would allow this large number of individual light failures to accumulate. Since the refueling outage this room has been posted as a "High Radiation Area" which may have reduced the number of tours in the room.

b. Lubrication Program Review

The inspector reviewed portions of the lubrication control program that has operations involvement. Operations routinely performs unscheduled additions of lubricants to equipment based on observations made during normal operator rounds. The inspector observed a weekly inventory for one of the storage cabinets containing lubricants for safety-related equipment. The content of the cabinet was well controlled and the lubricant containers were adequately labeled. The operator performing the inventory appeared knowledgeable of the process used to determine the correct lubricant for equipment and steps required to replenish lubricants in the storage cabinet.

The inspector did note that several storage cans had material issue tags dated in 1987. After questioning the licensee on the shelf life of these items, the inspector was informed that the current material control program only ensures acceptable shelf life prior to issuing of lubricant. The licensee reviewed the current inventory of stored lubricants, with regard to shelf life, and discovered that six cans of lubricant (out of approximately 40 cans in various storage cabinets) had expired shelf life dates. Engineering was contacted to review this issue and to evaluate the potential consequences of using lubricants that have an expired shelf life. Also, the inspector was informed by the licensee that improvements to the lubrication program are being reviewed. These changes would add the shelf life expiration date to the material identification tag for reference when the lubricant is being used and when the lubricant inventory is being performed. The inspectors will followup on the engineering review of previously used lubricants and on changes to the lubrication program.

While the inspector noted several strengths in the lubrication program involving operations, the inspector was concerned that the question of shelf life had not been identified earlier considering that some of the lubricants had been in storage cabinets for nearly five years.

No violations or deviations were identified.

5. ESF System Walkdown (71710)

The inspectors verified the operability of an ESF system by performing a walkdown of the accessible portions of the emergency feedwater system. The inspectors confirmed that the licensee's system line-up procedures matched plant drawings and the as-built configuration. The inspectors

looked for equipment conditions and items that might degrade performance (hangers and supports were operable, housekeeping, etc.). The inspectors verified that valves, including instrumentation isolation valves, were in proper position, power was available, and valves were locked as appropriate. The inspectors compared both local and remote position indications. Also, the inspectors verified that instrument calibrations were being performed on a routine basis.

During the walkdown inspection several minor deficiencies were identified. The licensee reviewed these items and initiated appropriate corrective action.

6. Onsite Follow-up of Events at Operating Power Reactors (93702)

a. Increased RCS Activity

On December 19, 1991, a RCS sample indicated that Iodine-131 activity was 0.0129 microcuries per milliliter which is indicative of failed fuel in the core. A normal level of activity is less than .005 microcuries per milliliter. Throughout the rest of the inspection period elevated levels of Iodine-131 were present, with a peak activity of 0.711 microcuries per milliliter occurring during the December 27, 1991 shutdown. This peak corresponded to a dose equivalent Iodine-131 level of 1.03 microcuries per milliliter which exceeded the TS 3.4.8 limit of one microcurie per gram. The TS limit was exceeded for less than two hours and then decayed down to approximately 0.02-0.04 where it stabilized. Toward the end of January, the activity trended slightly downward with the last sample indicating .0204 microcuries per milliliter. The licensee has been unable to identify the number, type, and locations of the fuel failures. The resident and regional inspectors will continue to monitor the RCS activity levels closely.

b. Unexpected Power Increase

On January 27, 1992, the "B" train safeguard slave relay test was performed. Part of the test closed those valves that receive a "Phase A" isolation signal which include the letdown isolation valves. During the restoration portion of the relay test, the operators noted an increase in power and T_{ave} and inward movement of the control rods. The operator immediately added boric acid to counteract the power increase. A later review of plant parameters identified that power peaked at 101 percent and T_{ave} increased approximately 1.5 degrees.

To identify the cause of the power increase, the licensee reviewed other plant parameters that could be related to reactivity changes. The letdown heater outlet temperature decreased to approximately 70 degrees Fahrenheit from a normal value of approximately 115 degrees during the time period that letdown was isolated. Volume control tank temperature also had a corresponding decrease. Based on these

temperature decreases and knowledge of operation of the CVCS demineralizers, the licensee believes that boron was removed from the cooler letdown water once letdown flow was re-established. The cooler RCS water with the reduced boron concentration was directed back to the core via normal charging flow and resulted in an increase in reactor power. The licensee's evaluation and assessment of this event is included in Attachment 1 to the inspection report. The initial corrective action proposed by the licensee to prevent recurrence is a change to slave relay test procedure that will bypass the CVCS demineralizers until the letdown flow temperatures have increased to normal values.

The operator's response to the power/temperature increase, and the procedure changes to prevent recurrence appeared to be appropriate.

7. Installation and Testing of Modifications (37828)

Modification (MRF 21561) replaced the offsite early warning siren activation system. The new activation portion of the system was previously installed for use with the existing sirens. A large number of inadvertent siren activations prompted the licensee to perform this modification. On January 23, 1992, the inspectors observed the full scale testing of the offsite early warning activation system. During installation of the new system, the licensee had performed a limited number of individual siren tests and silent tests of the activation system; however, this was the first test of the entire system.

The first test, which included all 106 sirens in the four surrounding counties (Lexington, Richland, Fairfield and Newberry), had a successful pass rate of 84 percent. For the second test, which activated the four counties individually, the pass rate was 79 percent. A loss of power to several sirens that coincided with the second test was the cause of the lower pass rate. The computer driven activation system which has the capability to monitor individual siren performance provided the information on the test pass rate.

After the test, the licensee performed an individual activation test on the 17 sirens that were reported as failures. Based on the results from these tests and data from the earlier tests, the licensee identified a computer software problem that effected nine sirens. These sirens activated properly; however, a timing problem with the computer resulted in the sirens being reported as failures. For the remaining eight sirens, the licensee identified hardware problems with the actual sirens or with the sensors that monitor the siren's performance. Corrective action was initiated for these items.

Overall, the licensee believes the test of the new activation system was a success. While a minor software problem was identified, the test also identified actual siren problems that would not have been discovered with the old activation system or test methods. Based on the inspector's

involvement with problems for the old activation system and the recent test observation, the new system appears to be a major improvement in the area of emergency preparedness.

8. Onsite Follow-up of Written Reports of Nonroutine Events at Power Reactor Facilities (92700)

(Closed) LER 90-05, Steam generator tube eddy current results. This report documented the results of the fifth inservice eddy current examination conducted during April, 1990. The results indicated that since more than one percent of the inspected tubes in each steam generator were defective, a C-3 inspection category, per TS 4.4.5.2 applied. The inspectors reviewed the report and verified that appropriate Region II and NRC Headquarters personnel were aware of the eddy current examination results. No further regional action is intended as a result of this report.

(Closed) LER 90-09, design defect in the chilled water system. The design defect involved the inability of the expansion tank instrumentation to detect a loss of inventory due to a postulated failure of the non-essential header, and the actuation of the non-essential header isolation valves. This could have resulted in a loss of chill water cooling to both trains of the charging/safety injection pumps and the component cooling pump motors. A permanent modification was made which separated the non-essential portions of chilled water from the safety-related chilled water system. The modification involved removing the non-essential header isolation valves and welding on pipe caps. This item is closed.

(Closed) LER 90-010, Inverter failure results in power reduction to 90 percent. This event was the result of a shorted ferroresonant transformer internal to one of the 120 VAC vital inverters (XIT-5901), which resulted in an inadvertent boration and a power reduction to approximately 90 percent power. There have been no other instances of this type of failure. Additionally, all of the 120 VAC vital inverters were replaced during the sixth refueling outage with new design inverters. This item is closed.

9. Exit Interview (30703)

The inspection scope and findings were summarized on February 4, 1992, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed the inspection findings.

No dissenting comments were received from the licensee. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during the inspection.

Item Number	Description and Reference
395/91-24-01	NCV - Failure to comply with TS 3.6.4 for an inoperable containment isolation valve (paragra h 2).
395/91-24-02	NCV - Failure to follow procedure in danger tagging the "A" EDG (paragraph 3).
395/91-24-03	URI - Failure to evaluate the cause of 15 safety-related circuit breaker failures (paragraph 3).

On February 20, 1992, F. S. Cantrell (DRP, RII) notified A. Koon (Manager, Nuclear Licensing) that as a result of further Region II supervisory review of the subject inspection report item 395/91-24-03 formally identified at the Exit Interview as a violation has been reclassified as an unresolved item until it can be further evaluated by the EDSFI team scheduled for March 1992.

10. Acronyms and Initialisms

AFD	Axial Flux Difference
CP	Chemistry Procedure
CVCS	Charging and Volume Control System
EDG	Emergency Diesel Generator
EDSFI	Electrical Distribution Safety Functional Inspection
EFPD	Effective Full Power Day
EMP	Electrical Maintenance Procedure
ESF	Engineered Safety Feature
I&C	Instrumentation and Control
IFT	Instrument Flow Transmitter
LCO	Limiting Conditions for Operations
LER	Licensee Event Reports
MCB	Main Control Board
MMP	Mechanical Maintenance Procedure
MOV	Motor Operated Valve
MRF	Modification Request Form
MWR	Maintenance Work Request
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
ONO	Off-Normal Occurrence
PASS	Post Accident Sample System
PMTS	Preventive Maintenance Task Sheet
RAOC	Relaxed Axial Offset Control
RCS	Reactor Coolant System
RHT	Recycle Holdup Tank
RWP	Radiation Work Permits
SAP	Station Administrative Procedure
SPR	Special Reports

SSPS	Solid State Protection System
STP	Surveillance Test Procedures
SW	Service Water
TS	Technical Specifications

ATTACHMENT 1

DESCRIPTION OF POWER PERTURBATION ON JANUARY 27, 1992

On January 27, 1992, while performing "B Train" Slave Relay Testing, STP-105.015, a power perturbation occurred as a result of testing the valves associated with Reactor Coolant System (RCS) letdown. RCS letdown is a portion of the Chemical Volume Control System, where reactor coolant is transferred for purification and returned to the RCS by the charging system. During the power perturbation, reactor power increased to 101 percent and RCS average temperature increased 1 degree to 588.6°F. Reactor power reduced to approximately 98 percent.

An analysis of the event concluded that the performance of the test results in the inventory within the letdown heat exchanger being cooled below its normal operating temperature. Once letdown was reestablished, this volume of colder water is transferred through the mixed bed demineralizers where boron atoms are removed. During the test, letdown flow is isolated for approximately five minutes. During this time, the RCS inventory contained within the letdown heat exchanger was cooled down an additional 48°F from the normal heat exchanger outlet temperature of 115°F. When letdown was restored, this cooler inventory was transferred through the in-service mixed bed demineralizers. The demineralizers reduced the boron concentration in this volume of RCS through ion exchange. The mixed bed demineralizers are pre-borated as part of normal system operation to preclude dilution of RCS inventory. As the resin within the bed is cooled, more boron can be stored at each ion exchange site. A reactivity balance was performed to quantify the change in RCS boron concentration to produce a one percent change in Reactor power. Those calculations demonstrated that a change of approximately 2.5 ppm in RCS boron was required. This is equivalent to a dilution of 90 gallons of non-borated water.

This test has been performed every 92 days since initial operations without impact on the plant. We conclude that a combination of effects resulted to produce the plant response. The test was performed near the beginning of core life, where a small dilution is required to change boron concentration and the test was performed in the winter, where the water utilized in cooling the letdown heat exchanger is colder and results in a further reduction in the temperature of the water within the letdown heat exchanger.