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

Report No.: 50-395/91-23

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: November 9 through December 17, 1991

Inspector: FOR R. W. Wright 1/6/92
R. C. Haag, Senior Resident Inspector Date Signed

Accompanying Personnel: L. A. Keller
L. P. King
R. W. Wright

Approved by: F. Cantrell 1/6/92
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, plant startup from refueling, installation and testing of modifications, onsite follow-up of events at operating power reactors, review of licensee self-assessment capabilty and information meetings with local officials. Selected tours were conducted on backshift or weekends. Backshift or weekend tours were conducted on eleven occasions.

Results:

The plant was in the final stages of the sixth refueling outage at the beginning of the inspection period and on November 15, 1991, the reactor was taken critical. The refueling outage ended on November 18, 1991, when the main generator breaker was closed and power increased to 30 percent. Total outage duration was 58 days. Later in the day, on November 18, 1991, the plant entered Mode 2 due to an inoperable feedwater isolation valve. On November 19, 1991, power operation resumed and the plant was taken to 27 percent power. On November 22, 1991, the plant again entered Mode 2 for maintenance and testing of the feedwater isolation valves. The plant resumed power operation on November 23, 1991, and reached 100 percent power on

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November 28, 1991. The plant remained at 100 percent power through the remainder of the inspection period.

While the overall effort for the plant startup from the refueling outage was good, several problems were noted. The initial estimated criticality prediction was not accurate and required a stop of startup activities until a new estimate was calculated. Air leakage at the seals in the new feedwater isolation valve actuators delayed the return to full power operation and required two separate entries into mode two (paragraph 7). A non-cited violation for failure to adequately maintain a surveillance test procedure for calibrating seismic monitors was identified (paragraph 2). Corrective action for control room annunciators and emergency diesel generator warning lights was not performed in a timely manner. A violation was cited for the emergency diesel generator warning light issue that resulted in an inoperable emergency diesel generator (paragraph 3). A review of control room staffing confirmed the licensee's ability to support the fire brigade with operations personnel. An incomplete hydrostatic pressure test of a service water modification resulted in a violation (paragraph 6). The meeting with local government officials and the NRC staff following the SALP presentation was both beneficial and informative (paragraph 9).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

W. Baehr, Manager, Chemistry and Health Physics
K. Beale, Supervisor, Emergency Services
*C. Bowman, Manager, Maintenance Services
*M. Browne, Manager, Design Engineering
*R. Campbell, Senior Engineer, Operating Experience
*B. Christiansen, Manager, Technical Services
H. Donnelly, Senior Engineer, Nuclear Licensing
*S. Furstenberg, Associate Manager, Operations
D. Goldston, Supervisor, Test Unit
D. Haile, Engineer, Nuclear Licensing
W. Higgins, Supervisor, Regulatory Compliance
*S. Hunt, Manager, Quality Systems
*A. Koon, Manager, Nuclear Licensing
D. Moore, General Manager, Station Support
K. Nettles, General Manager, Nuclear Safety
H. O'Quinn, Associate Manager, Maintenance Services
*C. Osier, Acting Manager, Systems & Performance Engineering
*C. Price, Manager, Technical Oversight
*J. Proper, Associate Manager, Quality Assurance
M. Quinton, General Manager, Engineering Services
L. Shealy, Senior Engineer, ISEG
J. Skolds, Vice President, Nuclear Operations
*G. Soult, General Manager, Nuclear Plant Operations
G. Taylor, Manager, Operations
*B. Williams, Manager, Planning and Regulatory Support

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.

G. Wunder, Project Manager, NRR, was onsite November 4-6, 1991, to meet with the resident inspectors, licensee management and tour the plant.

The NRC staff conducted a meeting on site November 14, 1991, to discuss the facility's SALP Report and met with local government officials following the SALP presentation to discuss the NRC/RII role and emergency planning issues.

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, test results were reviewed by personnel other than the individual directing the test, 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:

* Pressurizer heater capacity test (STP 506.001). Part of the effort to return the RCS to normal conditions following the outage included reducing the number of operating pressurizer backup heaters. Section "L" of SOP 101 directs the opening of individual heater group breakers to reduce pressurizer spray flow. After opening the breakers, the STP was performed to verify compliance with TS 3.4.3 which requires that the backup heater groups have a capacity of at least 125 kw. While reviewing the test results, the inspector noted that the STP gives a normal current value of 43 amps for backup group #1. The actual measured value was 26 amps. The licensee reviewed the basis for the current rating in the STP and indicated that the 43 amp value does not reflect present operating conditions. The inspector was informed that a STP change would be pursued based on additional review of this subject.

* Emergency diesel generator "A" operability test (STP 125.002). The inspector observed the diesel retest that was performed following trouble shooting activities for a "blown" fuse in a DC control circuit. (See paragraph 3.)

* Calibration of reactor building purge exhaust radiation monitor RMA-4 (STP 360.037).

* Seismic monitoring system triaxial response - spectrum recorders calibration (STP 391.005). The purpose of this procedure is to verify proper calibration and operability of the spectrum recorders. This procedure is required to be accomplished every 18 months per TS Surveillance Requirement 4.3.3.3.1. There are four sets of spectrum recorders throughout the plant. Each set of recorders consist of a horizontal, vertical and transverse recorder. Each recorder has twelve reeds with diamond tipped styluses. During a seismic event, each stylus etches a mark on a smooth metal plate. The length of these marks correspond to the magnitude of the acceleration felt by the recorders. Each reed operates at a discrete frequency, which

enables the construction of a frequency spectrum for any seismic event.

The inspector compared the licensee's calibration procedure to the latest revision of the vendor technical manual and noted that the acceptance criteria for frequency calibration in the licensee's procedure differed from the guidance in the technical manual. In the STP, the "as found" frequencies are compared with the nominal frequencies supplied by the vendor. An acceptance criteria of ± 7 percent is provided in the STP. However, the vendor's technical manual states that above a 5 percent difference from nominal values, the situation should be reviewed to determine the need for corrective action. Following consultations with the vendor, the licensee confirmed the 5 percent acceptance criteria, and that if a reed exceeds the 5 percent acceptance criteria, it should be replaced. The technical manual originally had a 7 percent acceptance criteria, but it was changed to 5 percent in a 1985 revision. The licensee failed to incorporate the revised acceptance criteria into their procedures. As a result, a total of ten reeds have exceeded the 5 percent acceptance criteria since 1985 without replacement or engineering review. The licensee has indicated that all reeds that have exceeded the 5 percent criteria in the past, or currently exceed the criteria, will be replaced at the first available opportunity. This NRC identified violation NCV 395/91-23-01 for failure to adequately maintain a procedure for surveillance and test activities of safety-related equipment is not being cited because criteria specified in section V.A of the NRC Enforcement Policy were satisfied.

A non-cited violation was identified involving the failure to adequately maintain a procedure for calibrating the Seismic Monitoring System Spectrum Recorders. An inadequate review of a technical manual revision resulted in the procedure deficiency. All other tests observed demonstrated acceptable results.

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:

* Preventive maintenance to change the bearing lube oil for "B" motor driven emergency feedwater pump XPP 21B (PMTS P0150738).

* Troubleshooting and repair of the ground indications for train "A" and "B" DC systems (MWR 9103421). The control room annunciators for a ground in the DC system were lit during the plant startup. During the outage new ground detection systems were installed. An MWR tag was located beside each annunciator window (both "A" and "B" train). These tags are used to indicate that an MWR has been generated to correct a deficiency. When the operators were questioned concerning the lit annunciators, the inspector was informed that the problems were being pursued by the MWR's. However, while reviewing the work progress on December 4, 1991, the shift engineer discovered that the MWR's had been previously cleared and electrical maintenance was not investigating the lit annunciators.

  Subsequent MWR's were written. The problem with "B" train ground detection system involved a lack of understanding the process for resetting the ground alarm. For "A" train, electricians discovered that the amp meter in the detection system was producing erratic indication and resulted in the ground alarms. The meter was removed for calibration. The licensee has also initiated daily battery reading for ground detection while the meter is removed.

  In conversation with the licensee, the inspector was informed that operations management discussed the continued DC ground annunciators with maintenance personnel and the need to investigate the problem. The licensee also believes these conversations contributed to the operator's belief that the MWR's referenced on the annunciator tags were being worked. After reviewing this issue, the inspector concluded that a weakness in communications between operation and maintenance occurred. This resulted in a lack of timely corrective action to an indicated plant deficiency. A more aggressive approach by operations for these annunciators would have allowed earlier return of the alarm capability. Also, a closer monitoring of indicated plant problems by system engineering could have provided more timely corrective action.

* Investigation and repair of a blown fuse in a DC control circuit for "A" emergency diesel generator (MWR 9102315). During the monthly surveillance test of the EDG, the "Loss of DC Power" annunciator was received. At the time operators were verifying the steady state no load voltage, which required pressing the "Emergency Start" pushbutton. The EDG was secured after receiving the alarm. Subsequent investigation identified a 15 amp blown fuse and a blown light bulb on the local EDG control panel which indicates that an "Emergency Start" had occurred. While replacing the bulb the electrician noted that the spring in the light socket was broken;

therefore, the socket was replaced. The electrician could not determine if the spring was broken while trying to remove the bulb or if the spring had been previously broken. Since the blown light bulb is powered by the DC circuit with the blown fuse and the timing of the occurrence (i.e. the annunciator came in when the emergency start was initiated) the licensee concluded that the blown fuse was caused by the light bulb/socket failure; however, the actual failure mechanism could not be determined. The licensee also identified that the loss of this DC circuit, due to the blown fuse, would have prevented closure of the EDG output breaker; therefore, rendering the EDG inoperable.

In May, 1989, NCN 3349 was written to request engineering support for repeated failures of the three indicating lights on the EDG control panels. The emergency start light is one of these three lights. The NCN noted that ten MWR's concerning failures had been written in the past four years. Since NCN 3349, an additional 12 MWRs were generated for continuing problems with the EDG warning lights. On May 1, 1990, the NCN was dispositioned and provided detailed instructions for installation of the light bulbs. The original disposition to the NCN was lost. This contributed to the lengthy time period (approximately one year) for the NCN response. The inspector questioned the licensee how these detailed instructions were disseminated and the controls used to ensure knowledgeable personnel were installing the light bulbs. Besides the NCN no additional instructions or controls were provided for the light bulb replacement. Also, the NCN stated that the light bulbs and sockets would be changed out with a different design in 1991. This modification was not completed in 1991, however, the inspector was informed that the modification is scheduled for implementation in January 1992. The existing sockets contain a spring coil which adds difficulty to installation of the light bulbs. The licensee believes this design is susceptible to cross threading of the bulb or incomplete seating of the bulb into the socket. This could allow overheating and failure of the bulb. After reviewing the MWRs the inspector noted some of the light bulb failures were described as "light bulb exploded." Also one of the MWRs described a + to - short inside the lamp socket. While the licensee stated that no previous warning light deficencies resulted in a blown fuse, the inspector determined that past problems have been more significant than light bulb failures.

A recent MWR (9103233) was written on November 4, 1991, for a bulb failure on "B" EDG control panel. The MWR description stated "Emergency start light exploded on emergency start". The MWR has not been worked yet. The licensee has not been aggressive in resolving the old design issue for the indicating lights nor in correcting current problems with the lights. The failure to resolve identified deficiencies is a violation (91-23-02) of 10 CRF 50, Appendix B, Criteria XVI, for failure to take prompt corrective action. The inspector was concerned that the licensee did not recognize the potential for a warning light failure to cause an EDG to be inoperable.

* Preventive maintenance to rebuild and test the air regulator for emergency feedwater flow control valve IFV 3551 (PMTS P0148599).

* Correction of leakage from the pressurizer power operated relief valves (PORV) (PCV 445A and PCV 445B). During startup from the refueling outage PCV 445A was isolated due to increasing tailpipe temperatures. TS 3.4.4 requires the block valve be closed and de-energized for an inoperable PORV. The licensee complied with the TS when leakage was identified. On December 4, 1991, after the plant had been operating several weeks and PORV temperature had completely stabilized, the block was opened to determine if leakage still existed. Tailpipe temperatures started to increase and the block valve was closed.

  On December 9, 1991, the block valve for PCV 445B was closed due to an increase in tailpipe temperature. This action disabled two of the three PORV's. On the following day PCV 445B was opened and then reclosed. Subsequently, the block valve was opened and tailpipe temperature carefully monitored. No leakage from PCV 445B was indicated by the tailpipe temperature, therefore, the block valve remained open. The same process (cycling the PORV) was completed for PCV 445A, however, leakage continued.

A violation involving failure to take prompt corrective action for the EDG indicating lights was identified. A weakness in communications between operations and maintenance resulted in control room annunciators not being returned to service in a timely manner. Prompt corrective action was not demonstrated for the two maintenance activities noted above.

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.

b. Review of the Operating Shift Crew Supporting the Fire Brigade

The inspectors conducted an evaluation of the operating shift crew staffing to determine if supporting the fire brigade with operations personnel would adversely affect the operating crew's ability to mitigate an accident. This inspection was conducted in response to a condition which recently occurred at another facility. At that facility, a fire occurred which identified the need to assign personnel to the fire brigade. This resulted in a heavier workload for the remaining on-shift control operators.

The staffing level for the operations crew and the fire brigade is provided in SAP 200, "Conduct of Operations". Three of the five positions for the fire brigade are filled by members of the on-shift operating crew. The normal operating crew, as designated by SAP 200, has nine positions. The number of operators actually assigned to each crew is greater than nine and typically, more than nine operators participate in shift coverage. Upon activation of the fire brigade, the six remaining operators satisfy the minimum required operation staffing that is specified in the Emergency Plan. Based on maintaining at least the normal crew of nine operators, both operations and fire brigade functions can be simultaneously fulfilled. However, the inspector questioned the wording in SAP 200 which states, "The normal crew size will be maintained at full complement unless unusual conditions warrant a reduction". No additional guidance is given regarding unusual conditions. The inspector was informed by operations management that a nine member crew is considered the minimum staffing and additional operators are called in to support a shift in order to maintain the "normal" crew size. Based on the inspectors not having observed on-shift crew with less than nine operators and the licensee's comment that previous shifts have included at least nine operators, the controls to ensure personnel are available for both operations and fire brigade functions appear adequate. The inspector asked the licensee to review SAP 200 to determine if the wording for a "normal crew size" of nine operators should be changed to "minimum crew size".

No violations or deviations were identified.

5. Plant Startup From Refueling (71711)

The inspector observed the following activities in the startup program and reviewed REP 170.001,"Refueling Startup Testing", which provides guidance and controls for these activities.

* RTD cross calibration during RCS heatup while in Mode 3 (REP 107.012). The calibrations were performed at RCS temperatures of 350, 450 and 550 degrees Fahrenheit using a new data gathering computer which sequenced through the individual RTD's and measured the resistance output. Actual temperatures are then generated from the resistance values.

* Comparison of the Digital Rod Position Indication (DRPI) versus the Integrated Plant Computer System (IPCS) indicated rod positions. No discrepancies were noted.

* Beginning of cycle dilution to criticality (REP 107.003). The inspector noted that criticality occurred at a boron concentration of 1822 ppm with control rod bank D at 165 steps, which differed from the original estimated critical boron concentration of 1867 ppm with bank D at 160 steps. This difference in boron concentration and control rod height corresponds to approximately 460 pcm reactivity. While this was within the licensee's acceptance criteria of 50 ppm boron concentration difference and/or 500 pcm reactivity difference, the licensee contacted Westinghouse for additional information. Westinghouse informed the licensee that this amount of discrepancy during startup from a refueling outage is not significant. The licensee is continuing to review this issue.

* Reactor core flux mapping using the movable incore detectors at 50 percent power (STP 212.001).

* Comparison of quadrant power tilt ratio (QPTR) as indicated from the excore nuclear instruments and from the incore flux map. This evaluation of the QPTR accuracy was performed at 50 percent power. The excore instruments indicated a QPTR greater than TS 3.2.4 limit of 1.02. This TS LCO is applicable for operation above 50 percent of

rated thermal power. However, this TS did not apply at the time due to the special test exemption (3.10.2) for core physics testing. Additionally, the indicated QPTR was not reliable since the excore nuclear instruments were last calibrated utilizing the previous core data. The incore flux map also indicated that there was a flux tilt slightly above 1.02. The inspector questioned the licensee to determine if this situation was acceptable for operation above 50 percent in the light of the TS 3.2.4 requirement. The licensee stated that the results of the incore flux mapping were not applicable to this TS. The licensee's policy is to use the incore map results to verify that the core peaking factors are within their limits and the reactor core conditions are consistent with the assumptions in the safety analysis. The licensee additionally verifies that there is sufficient margin, so that subsequent changes in power distribution within the QPTR limit of 1.02 will not result in the core peaking factors exceeding their limits. After this verification, the excore detectors are recalibrated to show a zero QPTR in order to detect any subsequent significant changes in QPTR. The inspectors consulted the Region and NRR regarding this policy. NRR stated that the licensee's policy is acceptable and consistent with current industry practice. Both the Region and NRR agreed with the licensee in that TS 3.2.4 does not apply until after the excore detectors have been recalibrated.

6. Installation and Testing of Modifications (37828)

   a. Upgrade of the Early Warning Siren System

   This modification (MRF 21561) replaced the offsite early warning siren activation system. Due to a large number of inadvertent siren activations, the licensee had previously decided to replace/update the activation portion of the system. The actual sirens remained intact. The inspector observed portions of the field work which involved installation of new receiver/transmitter and activation detection devices at each siren. The inspector also reviewed the new system controls for activating the early warning system and receiving feedback on system performance. The new activation system has the capability to automatically poll each siren and also provide continuous operational status for all sirens.

   Implementation of the MRF consisted of installing the entire system, both offsite and onsite (with the exception of the control room activation panel) portions. However, actual tie in to the individual sirens would not occur until the system was completely installed and tested. The existing activation system will remain active until all individual sirens are tied into the new system. The licensee estimates the change over to occur in early 1992. The new activation system appears to be a major improvement over the old system; however, actual operating time is needed to determine if the problem with inadvertent activations has been resolved.

b. Chill Water System Improvements

As part of the licensee's long term program to upgrade the chill water (VU) system, a modifications associated with the "C" chiller was completed. MRF 21746 installed a three inch bypass line with a globe valve around the chiller service water (SW) outlet valve. Previously a six inch butterfly style valve (XVB 3129 B or C) was used to throttle SW flow through the chiller. For lower SW temperatures the butterfly valve did not provide accurate throttling capabilities. The three inch globe valve will allow more effective control of SW for these conditions. In addition to the globe valve, two gate valves (XVG 3196 and 3197) were also installed as isolation valves to allow SW flow from the chiller to be routed into either train "A" or "B".

General note No. 5 of the MRF states that XVG 3196 and 3197 will serve as hydrostatic test boundaries and piping downstream of these valves does not require hydro testing. The basis for not doing a hydrostatic test was that the downstream piping was an open ended portion of a non-closed system; therefore, Section XI of the ASME Code did not require the test. After reviewing the system drawings and the valve lineup sheets for the hydrostatic test that was complete, the inspector noted that the new piping downstream of XVG 3196 and 3197 is not considered open ended. Existing valves XVB 3129A and D are isolation valves downstream of the new sections of piping. After further review, the licensee agreed that these sections of piping are not classified as open ended and should have been included in the hydrostatic test for the modification. The hydrostatic test was re-performed to include these sections of piping.

The test group wrote the hydrostatic test instructions (including the test boundaries) based on information in the MRF. Engineering reviewed the test instructions for accuracy, but did not identify the incorrect hydro boundary. The failure to hydrostatically test all portions of the new SW piping as required by ASME Code Section XI, Acticle IWD-5223 is a violation (91-23-03).

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

On November 18, 1991, the licensee entered mode one following their sixth refueling outage. After stabilization at 30 percent power, the "B" feedwater isolation valve (XVG 1611B) air accumulator pressure dropped below 500 psig which resulted in the applicable annunciator alarming in the control room. Operators verified locally that the valve actuator was leaking air. The licensee then declared the valve inoperable and entered into the Technical Specification Limiting Condition for Operation (LCO) 3.7.1.6, which required the inoperable valve be restored to operable status within 72 hours.

The actuator used on the feedwater isolation valves utilizes high pressure air, which is stored in an accumulator, to operate the valve. An attached pump on the actuator takes service air (approximately 90 psi) and pressurizes the accumulator to 560 psi. Part of the actuator consists of an air valve assembly which contains shuttle valves that allow high pressure air to be directed to, or bleed off of, the top or bottom of the actuator piston. Investigation revealed that a poppet seal inside one of the shuttle valves had failed, providing a path for leakage from the accumulator through the air valve assembly to an escape port. The attached air pump could not keep up with the leakage and the accumulator pressure bled down below 500 psi resulting in the control room annunciator. After initially declaring the valve inoperable, the licensee conservatively assumed the valve would require a stroke test consistent with TS surveillance requirement 4.7.1.6 after repairs, and therefore, reduced power and entered into mode two for post maintenance testing. Previously, the poppet seals had been replaced in "B" and "C" feedwater isolation valve actuators during repairs to correct air leakage. The seals were later replaced for "A" actuator to prevent similar air leaks.

The failed seal was replaced and the valve actuator was reassembled. The subsequent stroke test revealed that the stroke time of the valve had not been appreciably affected, and that there was still plenty of margin between the actual (3.6 seconds) and the TS required full closure time of 5 seconds. The valve was declared operable at 7:40 A.M. on November 19, 1991, and the licensee began increasing power. At 11:45 A.M. on the same day, while at 27 percent power, the "B" feedwater isolation valve air accumulator pressure again fell below 500 psi resulting in the valve being declared inoperable and entry into the 72 hour LCO. Subsequent investigation revealed that the same poppet seal had failed. The seal failures occurred at the base of the seal lip, leading the licensee to conclude that the seal design was inadequate for this high pressure application. The licensee was able to procure replacement seals which incorporated a wider seal area and a curved radius corner at the seal lip base.

The scope of the work involved in the seal replacement included:

* Removal of the "Air Valve Assembly" and "Air Valve Manifold Block" with the "A" train solenoid box. The air valve assembly which contains the shuttle valves, was removed from the block and disassembled in the shop.

* Removal of the "B" train solenoid box, from the air valve manifold block. This allowed the "B" train solenoid box to remain at the valve with the electrical connections intact.

* Replacement of the new designed poppet seals and various O-rings.

During this maintenance activity, the inspector questioned the licensee if the plant was going to reduce power to mode two in order to stroke test the valve prior to declaring it operable. The licensee indicated that they were considering whether a stroke test was required. Later during a conference call between the licensee and Region II, the licensee stated that it was their position that the nature of the maintenance performed would not affect the stroke time of the valve. This was based on the type of maintenance performed and that the testing done on the air valve assembly in the shop, in conjunction with a planned modified pressure drop test on the re-assembled valve, would be adequate to demonstrate that the valve performance parameters were within acceptable limits. The applicable code requirement, ASME section XI, subsection IWV-3200, "Valve Replacement, Repair and Maintenance", states the following:

> "When a valve or its control system has been replaced or repaired or undergone maintenance that could affect its performance, and prior to the time it is returned to service, it shall be tested to demonstrate that the performance parameters which could be affected by the replacement, repair, or maintenance are within acceptable limits." Maintenance as defined as adjustment of stem packing, removal of the bonnet, stem assembly, or actuator, and disconnection of hydraulic or electrical lines are examples of maintenance that could affect valve performance parameters.

The Region II staff felt that in light of the examples listed in the footnote (maintenance which is relatively minor in scope that could affect valve performance parameters), an IST valve test relief request may be necessary. A second conference call involving the licensee, NRR, and Region II, was held and the NRC position was stated that an IST relief request was necessary. The licensee indicated that they did not agree with the NRC's interpretation, but would submit a relief request. The inspector also questioned the licensee as to their intentions regarding replacement of the poppet seals in the "A" and "C" feedwater isolation valves with the improved design seals. After some deliberation, the licensee decided to reduce power to mode two in order to change out the seals in the "A" and "C" valves and perform a full stroke test and pressure drop test for all three valves. This decision made the IST valve test relief request unnecessary. The seals on the "A" and "C" valves were changed to incorporate the improved seal design and the testing on all three valves was satisfactory.

8. Review of Licensee Self-Assessment Capability (40500)

The inspector attended portions of a regularly scheduled meeting of the Nuclear Safety Review Committee (NSRC) on December 5, 1991. The presentation by the technical oversight group in the areas of potential safety issues and operating experience provided a good overview of activities while also providing detailed information on relevant safety issues.

The inspector noted that 125 distribution items were included in the agenda for NSRC discussion. These items are grouped as "Discussion of Distribution Items" and include PSRC meeting minutes, NRC inspection reports, LER's, correspondence, industry experience items, etc. With this large number of items, the inspector questioned the level of review that each item receives. For the previous two NSRC meetings, 107 and 136 items were distributed for review. The licensee noted that PSRC meeting minutes are divided among the NSRC members such that each member is only responsible for detailed review of two or three meeting minute packages. For the remaining items distribution of review responsibility is not made. The licensee informed the inspector that in recent years the number of items distributed has been reduced; however, an additional review would be made to determine if all the current items are required for the NSRC to perform it's safety assessment function.

9. Information Meetings with Local Officials (94600)

On November 14, 1991, local government representatives from Lexington County, Richland County, Fairfield County, Newberry County, and the State of South Carolina attended the SALP presentation given by the NRC to SCE&G. Following the SALP presentation, NRC representatives met privately with the local government representatives to discuss the mission of the NRC and Region II. The SALP presentation and factors used to determine SALP scores were discussed. The area of emergency planning and the interface between the licensee and the local officials for emergency planning issues were discussed in detail. Cooperation between the licensee and the local officials appears to be very good. A comment was made by a local official that these meetings with the NRC and local officials after the SALP presentation were beneficial, and asked about the possibility of having similar meetings at other utility SALP presentations. NRC officials indicated that this area would receive additional review.

10. Other Areas

On November 14, 1991, the Regional Administrator, the Deputy Director of Reactor Projects, the Deputy Director of Radiation Safety and Safeguards, NRR Project Representatives, and the Reactor Projects Section Chief visited and toured the site with the resident inspectors. Following the tour, the staff presented the 1990/1991 SALP report to the licensee.

11. Exit Interview (30703)

The inspection scope and findings were summarized on December 17, 1991, 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
395/91-23-01	NCV - Failure to adequately maintain a procedure for calibrating the seismic monitoring system spectrum recorders, paragraph 2.
395/91-23-02	Violation - Failure to correct a deficiency on the emergency diesel generator in a timely manner, paragraph 3.
395/91-23-03	Violation - Failure to perform adequately hydrostatic testing of a new section of piping, paragraph 6.

12. Acronyms and Initialisms

ASME	American Society of Mechanical Engineers
DC	Direct Current
EDG	Emergency Diesel Generator
ESF	Engineered Safety Feature
I&C	Instrumentation and Control
IST	Inservice Test
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MRF	Modification Request Form
MWR	Maintenance Work Request
NCV	Non-cited Violaiton
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSRC	Nuclear Safety Review Committee
PMTS	Preventive Maintenance Task Sheet
PORV	Power Operated Relief Valve
PSI	Pounds Per Square Inch
PSRC	Plant Safety Review Committee
RCS	Reactor Coolant System
RWP	Radiation Work Permits
SALP	Systematic Assessment of Licensee Performance
SAP	Station Administrative Procedure
SCE&G	South Carolina Electric and Gas
SOP	System Operating Procedure
SPR	Special Reports
STP	Surveillance Test Procedure
SW	Service Water
TS	Technical Specifications
VU	Chill Water