U. S. NUCLEAR REGULATORY COMMISSION

REGION II

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License No.:	NPF-12
Report No.:	50-395/98-02
Licensee:	South Carolina Electric & Gas (SCE&G)
Facility:	V. C. Summer Nuclear Station
Location:	P. O. Box 88 Jenkinsville, SC 29065
Dates:	February 22 - April 4, 1998
Inspectors:	B. Bonser, Senior Resident Inspector T. Farnholtz, Resident Inspector W. Stansberry, Reactor Inspector, RII (Sections S2.1, S4.1, S4.2, S6.1, S6.2, S6.3 and S7.1)
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EXECUTIVE SUMMARY

V. C. Summer Nuclear Station
NRC Inspection Report No. 50-395/98-02

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a six-week period of resident inspection; in addition, it includes the results of an announced inspection by a regional inspector.

Operations

- Operators acted promptly in response to a deaerator relief valve lifting and prevented a more significant challenge to plant operation (Section O1.2).

- A review of four admistrative control programs implemented by Operations identified inattention to or lack of awareness of administrative control details in three of the programs. The specific examples were: not recognizing an engineering evaluation should have been updated when the work scope changed; not caution tagging three non-safety related valves; and, not revising an operating administrative procedure when painting criteria were revised (Section O1.3).

- Compensatory actions for an emergency feedwater isolation issue were satisfactorily implemented (Section O1.4).

- The knowledge level and performance of the intermediate building operator during routine rounds were good. The observed diesel generator compensatory actions were effective to ensure diesel operability. The observed scope of the operator rounds was effective to ensure that potential equipment problems were identified (Section O4.1).

- A review of the V. C. Summer Institute For Nuclear Power Operations report concluded that the content of the report was consistent with recent NRC assessments of licensee performance (Section O8.3).

Maintenance

- Observed maintenance on a component cooling water pump, a molded case circuit breaker, and a diesel generator identified no concerns. Good work practices and techniques were noted (Section M1.1).

- Surveillance activities were conducted satisfactorily and in accordance with applicable procedures. Good planning for the tests was evident and communications during the tests were effective (Section M1.2).

- A pre-job briefing for a moisture separator reheater performance test was thorough, clear, and detailed. Expected plant response was discussed (Section M1.3).

- Reactor coolant pump (RCP) seal water flow transmitter preventive maintenance was performed adequately. A review of maintenance procedures for similar RCP seal water flow transmitters identified procedures of significantly different ages. Although the older revision was performed adequately the inspectors considered it a poor practice to not revise all applicable procedures together (Section M3.1).

- A licensee assessment and failure cause determination reports of four previous diesel generator failures adequately identified the root causes and corrective action (Section M8.2).

Engineering

- An engineering evaluation to allow gagging a secondary plant deaerator relief valve in the closed position and to allow raising the setpoint of a second deaerator relief valve was technically adequate (Section E1.1).

- An unresolved item was identified to assess the safety significance of raising turbine first stage pressure during moisture separator reheater testing on steam line isolation actuation setpoints. This was not addressed in the safety evaluation for the test (Section E1.2).

Plant Support

- A violation was identified for the failure of a security officer to prevent access to a vehicle until the vehicle search was completed. (Section S2.1).

- Security personnel possessed appropriate knowledge to carry out their assigned duties and responsibilities, including response procedures, use of deadly force, and armed response tactics (Section S4.1).

- The security organization's response capability to security threats, contingencies, and routine response situations, including drills, were consistent with the security procedures and the approved Physical Security Plan and the Safeguards Contingency Plan (Section S4.2).

- Management support for the security program was generally strong. A notable exception to this support was compensatory measures remaining in place for two years (Section S6.1).

- Management's administration of the security program was proactive and effective (Section S6.2).

- The total number of trained security officers and armed personnel immediately available to fulfill response requirements met Physical Security Plan requirements. One full-time member of the security organization who had the authority to direct security activities did not have duties that conflicted with the assignment to direct all activities during an incident (Section S6.3).

- Overall the licensee was effective in identifying, analyzing, and resolving security related problems. The adequacy of corrective actions to prevent recurring problems was found to be excellent. There were strengths in the maintenance program of the security equipment and system that supported plant operations and safety. The licensee was aware of the weakness in the security system due to aging equipment that could eventually lead to system degradation (Section S7.1).

Report Details

Summary of Plant Status

Unit 1 began this inspection period at 100 percent power. On March 8, power was reduced to 94 percent to reseat a deaerator relief valve. On March 14, power was returned to 100 percent following completion of maintenance on the deaerator relief valves. On April 4, power was reduced to 87 percent for main steam safety valve (MSSV) testing. Power was returned to 100 percent following completion of MSSV testing on April 4.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

O1.2 Response To Deaerator Relief Valve Lifting

a. Inspection Scope (71707)

The inspectors reviewed the response by operators to a deaerator relief valve lifting on March 8.

b. Observations and Findings

At about 8:58 a.m., on March 8, the intermediate building auxiliary operator, while on rounds, notified the control room that it appeared a deaerator (DA) relief valve was lifting. It was confirmed that DA relief valve XVR-2252A-HV was lifting. Control room operators also observed a corresponding decrease in DA level. In order to reduce pressure in the DA and reseat the relief valve the shift supervisor directed a power reduction. During the power reduction, DA relief valve XVR-2252B-HV also started to lift. At about 9:20 a.m., both relief valves reseated. At 9:35 a.m., the power reduction was stopped and power was stabilized at 94 percent.

The DA system is pressurized by the condensate pumps and provides sufficient head to meet the net positive suction head requirements for the feedwater booster pumps during steady-state operation. The prompt action by operators to reduce pressure in the DA prevented a loss of DA level control and a potential challenge to plant operation.

c. Conclusions

Operators acted promptly in response to a deaerator relief valve lifting and prevented a more significant challenge to plant operation.

O1.3 Review of Operations Administrative Controls

a. Inspection Scope (71707)

The inspectors reviewed several operations administrative control programs.

b. Observations and Findings

Control of Temporary Equipment

On March 10, 1998, the licensee generated Work Request (WR) 9805330 to install temporary demineralizers on the 412 foot level of the intermediate building to facilitate draining chromated water from the B Component Cooling Water (CCW) pump to replace the outboard seal. An engineering evaluation was attached to the Removal and Restoration (R&R) form to support the installation of the demineralizers. The evaluation was written for work on the B CCW pump and included considerations such as floor loading, impact on essential equipment, fire concerns, and flooding concerns. The B CCW pump work was completed, and the pump was tested and declared operable on March 11.

The licensee determined that similar seal replacement work would be performed on another CCW pump within a short time frame and elected to keep the demineralizers in place beyond the completion of the B CCW pump work. A revision to WR 9805330 was made to take out references to the B CCW pump and to make it generic to include all CCW pumps. The associated R&R remained in effect but personnel failed to identify that the supporting engineering evaluation should be updated to consider the increased time that the demineralizers would be in place. This oversight was discussed with cognizant personnel. An updated engineering evaluation was prepared. The results of the evaluation were the same. The requirement in Operations Administrative Procedure (OAP)-111.1 to have a R&R to track the demineralizer installation and removal was satisfied. However, operations demonstrated an inattention to administrative controls in not recognizing that the supporting engineering evaluation did not address the most current demineralizer application.

Equipment Misalignment Control

On March 18, the inspectors reviewed the equipment misalignment status and monthly misalignment audits. Equipment is allowed to be misaligned under specific guidelines given in OAP-105.2, "Equipment Misalignment Procedure," Revision 1. The purpose of the procedure is to allow short term misalignment of equipment and ensure proper configuration control. A review of the status log found that there was no listed misaligned equipment on the day of the review. The procedure requires that equipment exceeding 30 days of misalignment shall be evaluated for continued misalignment. If continued misalignment is required, a Caution Tagout shall be issued and the item(s) removed from the Equipment Misalignment Status Log. The inspectors review of 30 day evaluations for January, February, and March of 1998 identified that three valves, XVT00127A-AR, XVT00127B-AR, and XVT00127C-AR, had been misaligned since December 16, 1997. These three non-safety related valves were on the Condenser Air Removal system. The three misalignment evaluations the inspectors reviewed identified the misaligned valves but did not caution tag the valves. On March 16 the licensee identified the oversight and caution tagged the three valves. Since regulatory requirements were not applicable to configuration control of these three valves, no violation occurred. However, since the same equipment misalignment controls were used for both safety and non-safety related equipment, the inspectors were concerned that future similar administrative oversights, if not corrected, could result in problems controlling safety-related equipment. When the inspectors identified this concern to the licensee, a Condition Evaluation Report (CER) 98-0256 was prepared documenting the oversight. This was the second example of operation's inattention to administrative controls.

Control Room Painting

On March 24, the inspectors observed painting in the control room. A review by the inspectors of the controlling maintenance procedure and the operations procedure for painting identified that guidelines in the two procedures conflicted. The inspectors were concerned with the controls governing painting in the control room and the potential for degradation of ventilation system efficiency. The inspectors brought this issue to the attention of the shift supervisor. The shift supervisor reviewed the conflict and found that the requirements in Operations Administrative Procedure (OAP)-111.1, "Guidelines For Operations Department Special Instructions," Revision 1, were outdated.

Procedure OAP-111.1 limited touch up painting in the control room to 200 square feet per day or a total of 1000 square feet. Any painting in excess of the limits required an engineering evaluation. The procedure in use by the painters was Civil Maintenance Procedure (CMP)-500.003, "Application of Paint To Surfaces Outside The Reactor Building," Revision 4. The maintenance procedure allowed up to 1000 square feet of painting a day in the control room envelope. An engineering evaluation is necessary when painting a total of 4000 square feet. The inspectors observed that the painters were following the guidelines contained in the maintenance procedure. The maintenance procedure was based on an engineering review of painting in the control room. The inspectors reviewed the engineering analysis and it appeared satisfactory. The inspectors concluded that the painting in the control room was being performed in accordance with established procedures. The inspectors considered the outdated OAP as a third example of operation's inattention to administrative controls.

Equipment Bypass Authorization

On March 18, the inspectors reviewed the licensee's Bypass Authorization log book and the licensee's administrative controls for authorizing bypass installation (Station Administrative Procedure (SAP)-148). At the time the inspectors reviewed the log there were three active bypass authorizations. The oldest bypass had been installed in November 1997. Each of the bypasses was installed in accordance with the administrative controls and had received the appropriate 10 CFR 50.59 screening and had been approved by the Plant Safety Review Committee.

c. Conclusions

A review of four admistrative control programs implemented by Operations identified inattention to or lack of awareness of administrative control details in three of the programs. The specific examples were: not recognizing an engineering evaluation should have been updated when the work scope changed; not caution tagging three non-safety related valves; and, not revising an operating administrative procedure when painting criteria were revised.

O1.4 Emergency Feedwater (EFW) Isolation

a. Inspection Scope (71707)

The inspectors verified the licensee's compensatory actions in response to an issue concerning isolation of EFW.

b. Observations and Findings

On March 20, the licensee identified an issue concerning the ability to isolate EFW to a faulted steam generator for a secondary system pipe break outside containment. This issue was reviewed and is documented in NRC Inspection Report No. 50-395/98003.

The inspectors verified the implementation of the licensee's interim compensatory actions. They included a revision to the Emergency Operating Procedure (EOP) Users guide to describe operator actions for this event, and stationing an operator at the control room evacuation panels where EFW isolation can be performed. On several occasions during the inspection period the inspectors verified the operator stationed at the control room evacuation panels was attentive and knowledgeable of the required actions to be taken in response to a faulted steam generator. The inspectors identified no concerns.

c. Conclusions

Compensatory actions for an emergency feedwater isolation issue were satisfactorily implemented.

O4 Operator Knowledge and Performance

O4.1 Intermediate Building Operator Rounds

a. Inspection Scope (71707)

The inspectors accompanied the Intermediate Building (IB) operator during the performance of a routine tour and TS required log taking.

b. Observations and Findings

On March 29, the inspectors observed the routine activities of the IB operator which included a complete tour of the assigned spaces and the recording of logs. Areas toured in the IB included vital switchgear rooms, the reactor control rod equipment room, the control room evacuation panels, the Diesel Generator (DG) rooms, the main steam isolation valve area, and ventilation equipment areas. Also included were the Service Water (SW) building, and the fire pump and circulating water pump areas. The operator toured these areas in a systematic manner and inspected all areas. During the tour the IB operator also verified DG operability due to a failure of the A DG local annunciator panel. The annunciator failure had caused DG annunciators to alarm in the control room. As a compensatory action the IB operator verified locally that the DG was operable. Logs were recorded on a handheld electronic device which was later downloaded into a computer for data storage and reviewing. The operator demonstrated a good level of knowledge and familiarity with his duties and responsibilities.

c. Conclusions

The knowledge level and performance of the intermediate building operator during routine rounds was good. The observed diesel generator compensatory actions were effective to ensure diesel operability. The observed scope of the operator rounds was effective to ensure that potential equipment problems were identified.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) Violation (VIO) 50-395/97003-01: Failure to establish procedures appropriate to the circumstances. On April 26, 1997, the licensee failed to establish operating procedures that would enable operators to maintain adequate control of Steam Generator (SG) water levels and failed to provide adequate operating instructions for response to a turbine trip.

Corrective actions taken by the licensee included revising General Operating Procedure (GOP)-4, "Power Operation (Mode 1)." The inspectors verified that the revisions provided additional guidance to the operators for maintaining the required feedwater differential pressure during power escalation. Also, Abnormal Operating Procedure (AOP)-214.2, "Response to Load Rejection/Runback," Revision 3 was revised to provide additional guidance for response to a potential feedwater isolation as the result of a turbine trip due to high-high SG water levels. The inspectors reviewed these revisions and considered them to be adequate. The revised procedures were validated on the simulator and lessons learned from this event were incorporated into operator training scenarios.

O8.2 (Closed) VIO 50-395/97003-03: Failure to follow procedure to raise Reactor Building (RB) pressure. On April 13, 1997, the licensee failed to implement the requirements of System Operating Procedure (SOP)-114, "Reactor Building Ventilation System," when an operator opened the containment purge exhaust isolation valves instead of the reactor building alternate purge supply isolation valves as required by the procedure.

The licensee revised SOP-114 to show a clear difference between the purge supply and exhaust sections to clarify the different requirements for the operators. The inspectors reviewed the revision and determined that the revised procedure was improved in that the two operations (raising and lowering RB pressure) were each contained in separate sections. In addition, the licensee installed operator aids in the form of red plastic labels on the Heating, Ventilation, and Air Conditioning (HVAC) panel. The purpose of these tags was to help prevent inadvertent operation of the containment purge exhaust isolation valves. The inspectors considered these actions adequate to prevent recurrence of this event.

O8.3 Review of Institute For Nuclear Power Operations (INPO) Report

a. Inspection Scope (71707)

The inspectors reviewed the final INPO evaluation report for V. C. Summer.

b. Observations and Findings

The INPO onsite assessment was conducted during the weeks of June 23 and June 30, 1997. The inspectors reviewed the INPO report to identify any issues that were not consistent with NRC findings and assessments. The issues identified in the INPO report were found to be consistent with recent NRC assessments of licensee performance.

c. Conclusions

A review of the V. C. Summer INPO report concluded that the content of the report was consistent with recent NRC assessments of licensee performance.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707)

The inspectors observed all or portions of the following work activities:

- WR 9800102, B Component Cooling Water (CCW) Pump Outboard Seal Replacement.
- Preventive Maintenance Task Sheet (PMTS) 9801120, Inspect Fuel Injection Pump Studs on the A Diesel Generator (DG).
- PMTS P0211043, Inspection (Partial Teardown) of the A DG Main Air Start Valve B.
- PMTS P0211042, Inspection (Partial Teardown) of the A DG Main Air Start Valve A.
- PMTS 9801547, A DG Engine Quarterly Maintenance.
- WR 9718157, Repair A DG Number 11 Cylinder Lube Oil Leak Where Oil is Fed to Rocker Arm.
- WR 9717799, Replace Tubing from Gage Panel to Valve Before Failure -Starting Air Pressure Number 1.
- WR 9717800, Replace Tubing from Gage Panel to Valve Before Failure -Starting Air Pressure Number 2.
- WR 9800091, Replace Bound Up Stator Temperature Selector Switch.
- PMTS 9722364, Molded Case Circuit Breaker Testing XMC1DB24-12GH.

b. Observations and Findings

The observed maintenance activities were conducted using the appropriate procedures, tools, and techniques. The maintenance technicians were knowledgeable and demonstrated good work practices. No concerns were identified.

c. Conclusions

Observed maintenance on a component cooling water pump, a molded case circuit breaker, and a diesel generator identified no concerns. Good work practices and techniques were noted.

M1.2 Surveillance Observation

a. Inspection Scope (61726)

The inspectors observed or reviewed the following surveillance testing activities:

STP-123.003B, Train B Service Water System Valve Operability Test, Revision 3.

STP-116.001. Reactor Building Cooling Unit Functional Test. Revision 5.

STP-117.001. Iodine Removal System Test. Revision 3.

STP-125.002. Diesel Generator Operability Test. Revision 18

b. Observations and Findings

Observation and review of surveillance testing found good planning, communications and procedural adherence. Test acceptance criteria were met.

c. Conclusions

Surveillance activities were conducted satisfactorily and in accordance with applicable procedures. Good planning for the tests was evident and communications during the tests were effective.

M1.3 Moisture Separator Reheater (MSR) Testing

a. Inspection Scope (62707)

The inspectors attended a pre-job briefing for performing an MSR test. The attendees included on shift operators and the engineer in charge of the test.

b. Observations and Findings

On March 16, 1998, the inspectors attended a pre-job briefing for the performance of Preventative Test Procedure (PTP)-230.001, "MSR Steam Flow Setup and Verification," Revision 3. The purpose of the test was to verify the optimal operation of the MSRs.

The pre-job briefing was conducted by the engineer in charge. The inspectors considered the briefing to be thorough, clear, and detailed. The details of the test and the expected plant response was discussed. All questions were addressed.

c. Conclusions

A pre-job briefing for a MSR performance test was thorough, clear, and detailed. Expected plant response was discussed.

M3 Maintenance Procedures and Documentation

M3.1 Observation and Review of Flow Transmitter Calibration Procedures

a. Inspection Scope (61726)

The inspectors observed performance of preventive maintenance on a Reactor Coolant Pump (RCP) seal water flow transmitter and reviewed the procedures.

b. <u>Observations and Findings</u>

On March 13, the inspectors observed Instrument and Control (I&C) technicians perform Instrument Control Procedure (ICP)-340.022, "RCP 3 Seal Water Flow IFT00124," Revision 3, to complete PMTS 9717006. The inspectors observed testing of the transmitter and reviewed the procedure. The testing was performed satisfactorily and no concerns were identified.

The inspectors reviewed the procedures for the similar flow transmitters in the other two RCP seal water loops. The procedure the inspectors observed the I&C technicians utilizing was dated March 14, 1986. The inspectors identified that the similar procedure for RCP 1 seal water loop, ICP-340.024, "RCP 1 Seal Water Flow IFT00130," Revision 4, was dated July 7, 1994. The inspectors were concerned that procedures of significantly different ages were being used on similar transmitters and that all the procedures for the similar flow instruments had not been updated since 1986.

The inspectors review of both procedures identified several differences. These included a different procedure format, different references to test equipment and the plant computer, and the inclusion of steps for lifted leads and fitting replacement in the newer procedure. The older procedure required going to other procedures to document lifted leads or fitting replacements. The inspectors found that licensee guidelines for procedure revisions contained in Station Administrative Procedure (SAP)-139, "Procedure Development, Review, Approval and Control," Revision 18, did not specifically require a timeframe for updating procedures. The inspectors concluded that the older revision was adequate to perform the maintenance. However, the inspectors considered not revising all applicable procedures for other similar instrument loops when a revision was made to an instrument loop procedure was a poor practice.

c. <u>Conclusions</u>

Reactor Coolant Pump (RCP) seal water flow transmitter preventive maintenance was performed adequately. A review of maintenance procedures for similar RCP seal water flow transmitters identified procedures with revisions that were eight years apart. Although the older revision was performed adequately, the inspectors considered not revising all applicable procedures together was a poor practice.

M8 Miscellaneous Maintenance Issues (92902, 92903)

M8.1 <u>(Open) Unresolved Item (URI) 50-395/98001-01</u>: Review solid state protection system TS operability and testing requirements. The inspectors verified that procedures STP-345.037, "Solid State Protection System Actuation Logic and Master Relay Test Train A," Revision 14, and STP-345.074, "Solid State Protection System Actuation Logic and Master Relay Test Train B," Revision 9, were revised. Procedure STP-345.037 was revised on January 29 and performed on January 30, 1998. Procedure STP-345.074 was revised on February 17 and performed on February 20.

1998. The procedures were revised to verify that the parallel inputs for high-high SG level and SI were tested in the feedwater isolation circuitry.

The licensee documented this issue on January 23, 1998, in CER 98-0087. This was based on a Westinghouse Technical Bulletin dated December 20, 1997. The licensee considered these procedural changes as an enhancement to their Solid State Protection System (SSPS) testing and considered the surveillance tests to be adequate prior to making the changes in the surveillance test procedure. The inspectors questioned the licensee's position on this issue based on the definition of Actuation Logic Test in the TS. The TS definition states that an Actuation Logic Test shall be the application of various simulated input combinations in conjunction with each possible interlock logic state and verification of the required logic output. On March 19, the licensee reevaluated their position on this issue and concluded that the SSPS surveillance testing was not adequately testing these circuits and the inadequate surveillance testing was reportable. On March 23, during a telephone conference with NRC staff, the licensee stated that they had reevaluated their position on this issue. The NRC staff is continuing to review the licensee's resolution to the inadequate TS surveillance testing and how these actions compare to TS required actions for inadequate surveillance testing.

M8.2 <u>(Closed) Inspection Followup Item (IFI) 50-395/97013-01</u>: Licensee's effort to identify the root cause and corrective action for the A diesel generator problems. In response to the four failures of the A DG the licensee performed an independent assessment of the failures and performed Failure Cause Determinations for each of the failures. The inspectors reviewed each of the licensee's assessments.

The independent assessment of the licensee's actions in response to the A DG problems concluded that the A DG was operable and recurrence of the instability would not be expected. This conclusion was based on the corrective actions taken by the licensee, analysis results by Woodward, the governor vendor, bench testing of components on site, and completion of comprehensive post-maintenance testing. Failure analysis results performed on the suspect components verified that the abnormal conditions observed on the A DG were attributable to the component failures. It was concluded that no common component failure linked the four failures on the A DG. The inspectors concluded that the licensee had adequately reviewed and identified the root cause of each A DG problem.

The independent assessment also made several recommendations. These recommendations included suggested improvements in the process for controlling troubleshooting activities and governor set-up procedures; improvements in training of operations and maintenance personnel and adjustment of the governor system; and the documentation of all unexpected events during maintenance and troubleshooting. Several other testing and maintenance recommendations were made by the assessment team. The assessment team also concluded that the licensee's actions taken and responses provided to industry information documents were inadequate with regards to the information directly applicable to the recent events at Summer. The licensee prepared a summary of corrective actions and proposed completion dates. The inspectors concluded that the independent assessment of the A DG events had provided the licensee with useful feedback and proposed enhancements to licensee programs.

The inspectors also reviewed the Failure Cause Determination reports prepared by engineering for each of the four A DG problems. The inspectors were satisfied that the licensee had adequately reviewed each A DG issue and proposed corrective actions. The failure reports concluded the following: 1) the A DG load swings experienced on November 11, 1997, and December 2, 1997, were attributed to failure of the governor electronic control (EGA) unit; 2) the A DG load swings on November 21, 1997, were attributed to a failure of the relay which caused droop to not be inserted properly and resulted in improper load sharing between the A DG and the grid; and 3) the A DG problem on December 30, 1997, that resulted in a plant shutdown, was attributed to a failure of the governor hydraulic actuator (EGB) unit. The inspectors concluded that the licensee had identified the root cause of the A DG problems and proposed adequate corrective action. Based on this review and earlier reviews of the A DG failures the inspectors did not identify any violations of regulatory requirements. Closeout of this IFI also closes all required followup reviews for Notice of Enforcement Discretion (NOED) 97-2-003 which was granted on November 13, 1997, for a twelve hour extension of the TS Action Statement involving the first A DG failure.

III. Engineering

E1 Conduct of Engineering

E1.1 Review of Engineering Evaluation for Deaerator Relief Valve Lifting

a. Inspection Scope (37551)

The inspectors reviewed an engineering evaluation concerning a DA relief valve which lifted on March 8, 1998.

b. Observations and Findings

On March 8, 1998, a DA relief valve (XVR-2252A-HV) lifted at a system operating pressure of approximately 107 psig (See Section O1.2). Plant power was reduced until the valve reseated at a pressure of approximately 99 psig. In addition, a second DA relief valve (XVR-2252B-HR) showed evidence that it had lifted and reseated during the same event.

The setpoint for these two valves (A and B) was 116 +/- 3 psig to correspond to the maximum allowable working pressure for the DA. When the A valve lifted and reseated, it was observed that there could be a mechanical problem with the valve internals which could potentially prevent the valve from reseating if it lifted again. The licensee performed an engineering evaluation to allow the A valve to be gagged in the closed position. To do this, the licensee calculated the DA relief valve flow capacity to ensure that sufficient capacity would be available with the A valve gagged closed. In addition to the A and B valves, the DA has two other relief valves installed to prevent over pressurization (XVR-1304-EX and XVR-1306-EX). The total flow capacity was calculated through the three operable valves and it was determined that a sufficient design margin existed to allow the A valve to be gagged closed.

In addition to gagging the A valve closed, the licensee performed an engineering evaluation to raise the setpoint pressure of the B valve to 121 +0/-8 psig. This would continue to meet the American Society of Mechanical Engineers (ASME) Code allowance for the DA. The maximum working pressure for the DA is 116 psig. The ASME Code specifies that no pressure relieving devices can be set higher than 105 percent of the maximum working pressure (121 psig for the DA).

The inspectors reviewed the engineering evaluation and calculations and determined that they were adequate to provide reasonable assurance that the DA would continue to be overpressure protected with the new configuration until such time that the permanent repairs could be performed. The method used represented good engineering practice and contained all necessary data. No concerns were identified.

Also contained in the engineering evaluation were three 10 CFR 50.59 screenings to allow gagging closed the A relief valve, to allow in-place testing of the A and B valves, and to raise the setpoint of the B valve. These screenings were sufficiently detailed to support that no 10 CFR 50.59 evaluations were required.

c. Conclusions

An engineering evaluation to allow gagging a secondary plant deaerator relief valve in the closed position and to allow raising the setpoint of a second deaerator relief valve was technically adequate.

E1.2 Turbine First Stage Steam Pressure Changes

a. Inspection Scope (37551)

The inspectors reviewed the effect of changing main turbine first stage pressure during MSR testing.

b. Observations and Findings

On March 16, the licensee began MSR steam flow testing (see Section M1.3) to establish the optimal amount of high pressure steam flow to the High Pressure (HP) turbine and the MSRs. The licensee believed by rebalancing steam flow between the MSRs and the HP turbine, greater secondary plant efficiency could be obtained. The actual test was well controlled and involved decreasing steam flow to the MSRs and increasing steam flow to the HP turbine incrementally. The test was performed slowly over several days to allow the plant to reach equilibrium after each incremental change.

The steam flow rebalancing had the effect of increasing HP turbine first stage steam pressure as indicated on pressure transmitters IPT-446 and IPT-447. These steam pressure transmitters provide input into the rod control and steam dump control systems, and provide inputs into the protection channels used to calculate the high steam flow coincident with Lo-Lo Tave main steam line isolation setpoint. On March 23, during the conduct of the test, the operations shift engineer questioned the effect of the change on first stage pressure on the protection channels. The test had raised first stage pressure from a normal pressure of about 676 psi to a peak of 711.7 psi on March 23. The test was terminated and the MSRs were placed back in service in accordance with the system operating procedure.

The steam line isolation engineered safeguards feature system actuation instrumentation requirements are given in TS 3.3.2, Table 3.3-3, 4.d and Table 3.3-4, 4.d. The high steam line flow setpoint is described in TS as a function of load corresponding to 40 percent of full power steam flow between zero and 20 percent load followed by a linear ramp to 110 percent of full power steam flow at 100 percent load. Turbine first stage pressure is used as a measure of percent load. At the end of the inspection period the licensee was continuing to evaluate the potential effects of increasing first stage turbine pressure prior to resuming the test.

The inspectors reviewed the safety evaluation for increasing steam flow to the HP turbine. A discussion of the effects on the high steam line flow accident and the main steam isolation setpoint had not been included in the safety evaluation. Pending completion of the licensee's evaluation to assess the safety significance of raising turbine first stage pressure, this issue is identified as URI 50-395/98002-01.

c. Conclusions

An unresolved item was identified to assess the safety significance of raising turbine first stage pressure during moisture separator reheater testing on steam line isolation actuation setpoints. This was not addressed in the safety evaluation for the test.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 General Comments (71750)

The inspectors observed radiological controls during the conduct of tours and observation of maintenance activities and found them to be acceptable.

S2 Status of Security Facilities and Equipment

S2.1 Protected Area Access Control-Vehicles

a. Inspection Scope (81700)

The inspectors evaluated the licensee's vehicle access control program for packages, personnel and vehicles entering the protected area. This was to ensure compliance with criteria in Sections 1 and 3 of the Physical Security Plan (PSP) and Security Plan Procedures (SPPs) 202 and 203.

b. Observation and Findings

The inspectors reviewed applicable access control procedures to ensure that the licensee provided appropriate access controls for the protected areas.

The inspectors verified that personnel, hand-carried packages or material, and delivered packages or materials were searched adequately before being admitted to the protected area. The inspectors observed that security personnel searched for firearms, explosives, incendiary devices, and other items that could be used for radiological sabotage. These searches were either by physical search or by search equipment.

The inspectors found the following circumstances concerning personnel access control at the Vehicle Access Portal (VAP). A coded, numbered, picture badge identification system was used for personnel who were authorized unescorted access to the protected area through the VAP. Picture badges issued to nonlicensee personnel indicated authorized access areas and showed that no escort was required. The licensee used biometric hand geometry to ensure personal identification of individuals entering the protected area at the VAP.

The inspectors verified that access control program records were available for review and contained sufficient information for identification of persons and vehicles authorized access to the protected area.

During an evaluation of vehicle access control at the VAP, the inspectors observed two individuals, a vehicle operator and accompanying personnel, being processed through the personnel search equipment. They were cleared for access to the protected area by the security biometric system before the vehicle was searched. The first individual cleared went from the VAP search building directly to the unsearched vehicle and began to unload material from the vehicle to be searched by the security officer. SPP 202, "Vehicle Access Requirements," Revision 11, paragraph 5.3.3.A.1.2).c), states that when a security officer conducts a search of a vehicle, the security officer is to ensure that neither the operator nor the accompanying personnel are provided access to any portion of the vehicle until the vehicle search is completed. The failure to search a vehicle properly before the vehicle entered the protected area is identified as a Violation (VIO) 50-395/98002-02.

c. Conclusions

A violation was identified for the failure of a security officer to prevent access to a vehicle until the vehicle search was completed.

S4 Security and Safeguards Staff Knowledge and Performance

S4.1 Security Force Knowledge

a. Inspection Scope (81700)

The inspectors interviewed and observed security personnel to determine if they possessed adequate knowledge to carry out their assigned duties and responsibilities, including response procedures, use of deadly force, and armed response tactics.

b. Observations and Findings

The inspectors randomly interviewed approximately 20 security personnel, including supervisors, and witnessed approximately 30 others in the performance of their duties during normal and security event conditions. Members of the security force were knowledgeable in their duties and responsibilities, response commitments and procedures, and armed response tactics. The inspectors found that armed response personnel had been instructed in the use of deadly force as required by 10 CFR Part 73.

c. Conclusions

Security personnel possessed appropriate knowledge to carry out their assigned duties and responsibilities, including response procedures, use of deadly force, and armed response tactics.

S4.2 Response Capabilities

a. Inspection Scope (81700)

The inspectors evaluated the security organization's response capability to security threats, contingencies, and routine response situations, including drills to ensure consistency with the security procedures, the approved PSP, and Safeguards Contingency Plan (SCP).

b. Observations and Findings

The inspectors reviewed the response commitments of the SCP in the following areas: deadly force, central and secondary alarm station operations, communications, and security system degradations. Response personnel were required to be competent in these skills before doing response duties. As stated in S4.1, response personnel interviewed were knowledgeable of their responsibilities and duties indicated in these skills. The licensee conducted two table top drills and two response exercises during the inspection. The inspectors observed the drills and exercises, and reviewed the critiques. The critiques stated the number of adversaries and their objectives involved in each drill. The performance of each response member was indicated and any strengths or weaknesses were noted.

c. Conclusions

The security organization's response capability to security threats, contingencies, and routine response situations, including drills, were consistent with the security procedures, the approved Physical Security Plan, and the Safeguards Contingency Plan.

S6 Security Organization and Administration

S6.1 Management Support

a. Inspection Scope (81700)

The inspectors evaluated the level of management support for the security program.

b. Observations and Findings

The inspectors verified that station and security management support was thorough in identifying, reviewing, and analyzing the root cause of problems, setting priorities for corrective actions and, usually, timely correcting identified problems. The problems of the security computer system were reviewed and are discussed in S7.1. The inspectors reviewed the progress to correct the protected and vital area violation stated in the Safeguards Information Inspection Report No. 50-395/96-03, dated March 22, 1996. The compensatory measures implemented to temporarily secure the subject areas were still in place. The inspectors indicated that compensatory measures which are two years old were not indicative of proactive management support for the security program.

c. Conclusions

Management support for the security program was generally strong. A notable exception to this support was compensatory measures remaining in place for two years.

S6.2 Management Effectiveness

a. Inspection Scope (81700)

The inspectors evaluated the effectiveness of management's administration of the security program.

b. Observations and Findings

The inspectors verified station and security management had established organizational goals and objective measures necessary to determine security effectiveness. Management has ensured that responsibility for all necessary activities were assigned to qualified subordinates as evident by Security Plan revisions and organizational improvements. This effectiveness was also found in the security training improvements described in Section S5.1 of Safeguards Information Inspection Report No. 50-395/96-06. Management's review and follow-up of the performance of delegated responsibilities were done by personal observations, formal channels for opinions from subordinates, internal and external audits, and tracking and trending of security events.

c. Conclusions

Management's administration of the security program was proactive and effective.

S6.3 Staffing Level

a. Inspection Scope (81700)

The inspectors evaluated the total number of trained security officers and armed personnel immediately available at the facility to fulfill response requirements specified in the PSP. The inspectors also determined if one full-time member of the security organization, who had the authority to direct security activities, did not have duties that conflicted with the assignment to direct all activities during an incident.

b. Observations and Findings

The inspectors verified that the licensee has an onsite physical protection system and security organization. The security organization and physical protection system were designed to protect against the design basis threat of radiological sabotage as stated in 10 CFR 73.1(a). The inspectors verified that at least one full-time manager of the security organization was always onsite and had no duties that conflicted with the assignment to direct all activities during an incident. This individual had the authority to direct the physical protection activities of the organization. The inspectors reviewed four shift rosters and interviewed security force personnel on two shifts. The licensee had the number of trained security officers and armed personnel immediately available to fulfill response requirements and commitments of the PSP.

c. Conclusions

The total number of trained security officers and armed personnel immediately available to fulfill response requirements met Physical Security Plan requirements. One full-time member of the security organization who had the authority to direct security activities did not have duties that conflicted with the assignment to direct all activities during an incident.

S7 Quality Assurance in Security and Safeguards Activities

S7.1 Effectiveness of Management Control

a. Inspection Scope (81700)

The inspectors evaluated the overall effectiveness of the following: licensee's controls for identifying, analyzing, and resolving problems; determine adequacy of corrective actions to prevent recurring problems; and determine whether there are strengths or weaknesses in the controls for issues that could enhance or degrade plant operations or safety.

b. Observations and Findings

The inspectors reviewed documented security issues, events, and problems to determine the adequacy of the licensee's controls and effectiveness in the following: initial identification of the problem; elevation of the problems to the proper level of management for resolution; root cause analysis; disposition of operability problems; implementation of corrective actions; and expansion of the scope of corrective actions to include related systems, equipment, procedures, and personnel actions. The inspectors also reviewed documented security issues, events, and problems to determine the strengths or weaknesses in the licensee's controls. These areas have been addressed in Sections S4.1, S4.2, and S6.1, S6.2, and S6.3.

Discussions with maintenance personnel and reviews of the Security Events Logs, Summaries, and Work Orders revealed that there was a potential weakness in having sufficient spare parts on hand to maintain the security computer system for the next five years. The system was installed in the late 1980s. Presently, security maintenance personnel were doing an exceptional job in maintaining the security system. The prompt and thorough sevicing of the security system was notable. Record reviews indicated that the number of equipment failures was progressively escalating. This may result in a system degradation. The licensee indicated that there was approximately five years of spare parts available onsite, if the maintenance and repairs of the system degradation do not increase substantially. The licensee was aware of this problem and has plans to update the security computer system within the next five years.

c. Conclusions

Overall the licensee was effective in identifying, analyzing, and resolving security related problems. The adequacy of corrective actions to prevent recurring problems was found excellent. There were strengths in the maintenance program of the security equipment and system that supported plant operations and safety. The licensee was aware of the weakness in the security system due to aging equipment that could eventually lead to system degradation.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on April 20, 1998. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

F. Bacon, Manager, Chemistry Services
L. Blue, Manager, Health Physics
S. Byrne, General Manager, Nuclear Plant Operations
R. Clary, Manager, Quality Systems
M. Fowlkes, Manager, Operations
S. Furstenberg, Manager, Maintenance Services
D. Lavigne, General Manager, Nuclear Support Services
G. Moffatt, Manager, Design Engineering
K. Nettles, General Manager, Strategic Planning and Development
L. Hipp, Manager, Nuclear Protection Services
A. Rice, Manager, Nuclear Licensing and Operating Experience
G. Taylor, Vice President, Nuclear Operations
R. Waselus, Manager, Systems and Component Engineering
R. White, Nuclear Coordinator, South Carolina Public Service Authority
B. Williams, General Manager, Engineering Services
G. Williams, Associate Manager, Operations

INSPECTION PROCEDURES USED

IP 37551: Onsite Engineering
IP 61726: Surveillance Observations
IP 62707: Maintenance Observations
IP 71707: Plant Operations
IP 71750: Plant Support Activities
IP 81700: Physical Security Program for Power Reactors
IP 92901: Followup - Plant Operations
IP 92902: Followup - Maintenance
IP 92903: Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-395/98002-01	URI	assess safety significance of raising first stage turbine pressure (Section E1.2)
50-395/98002-02	VIO	failure to search vehicles according to Security Plan Procedures (Section S2.1).

Closed

50-395/97003-01	VIO	failure to establish procedures appropriate to the circumstances (Section 08.1)
50-395/97003-03	VIO	failure to follow procedure to raise reactor building pressure (Section 08.2)
50-395/97013-01	IFI	licensee's effort to identify the root cause and corrective action for the "A" diesel generator problems (Section M8.2)

Discussed

50-395/98001-01	URI	review solid state protection system TS operability and testing requirements (Section M8.1)