UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0.99

Report No.: 50-395/95-01

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

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

Facility Name: Virgil C. Summer Nuclear Station

Inspection Conducted: January 1-28, 1995

Inspectors: For R. W. Wright 2/10/95
R. C. Haag, Senior Resident Inspector Date Signed

For R. W. Wright 2/10/95
T. R. Farnholtz, Resident Inspector Date Signed

R. W. Wright 2/10/95
R. W. Wright, Project Engineer, RII Date Signed
(January 23-27, 1995)

Approved by: Floyd S. Cantrell Jr 2/10/95
Floyd S. Cantrell, Chief Date Signed
Reactor Projects Section 1B
Division of Reactor Projects

SUMMARY

Scope:

This routine inspection was conducted by the resident inspectors onsite in the areas of operational safety verification; freeze protection; onsite response to events; followup on previous operations, maintenance, and engineering findings; maintenance observations; surveillance observations; foreign material exclusion controls; plant support activities; and onsite followup of written reports of nonroutine events at power reactor facilities. Selected tours were conducted on backshift or weekends. These tours were conducted on January 16, 19, 26 and 27, 1995.

Results: (Summarized by SALP functional area)

Operations

The power reduction, increase, and plant manipulations associated with the switchyard repair work were well performed and deliberate. Operator awareness has been increased with regard to a degraded number 2 seal on the "A" reactor coolant pump. The freeze protection program was well implemented. Poor labeling/identification was noted for the condensate storage tank heat tracing circuits.

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Maintenance and Surveillance

The licensee's program for monitoring the performance and inspecting the diesel air inlet filter elements was adequate to identify when they required replacement. The oil analysis routinely performed on oil drained from the bearings of safety-related equipment only analyzes for magnetic particles. Discoloration of the "C" chill water chiller's oil and a dark brown color on the lower oil sight glass, could hamper the operator's ability to detect a change/lowering of the oil level. An effective program has been established for foreign material exclusion control, with the program requirements generally implemented properly.

Engineering and Technical Support

The review of a previous unresolved item, for the one time decrease in turbine control valve test frequency, concluded that the use of probability risk analysis in the 10 CFR 50.59 evaluation was appropriate.

Plant Support

The licensees efforts to replace the existing fire detection system with an upgraded system was considered a strength. Overall, the key control program was properly implemented and involved individuals were knowledgeable of the program requirements.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*L. Blue, Manager, Health Physics
*M. Browne, Manager, Design Engineering
F. Bacon, Manager, Chemistry
*C. Fields, Manager, Materials and Procurement
*M. Fowlkes, Manager, Nuclear Licensing & Operating Experience
*S. Furstenberg, Manager, Maintenance Services
*S. Hunt, Manager, Quality Systems
*D. Lavigne, General Manager, Nuclear Safety
*D. McGlauflin, Security Coordinator
*J. Nesbitt, Manager, Technical Services
*K. Nettles, General Manager, Station Support
*H. O'Quinn, Manager, Nuclear Protection Services
*M. Quinton, General Manager, Engineering Services
*G. Taylor, Vice President, Nuclear Operations
*R. White, Nuclear Coordinator, SC Public Service Authority
*B. Williams, Acting General Manager, Nuclear Plant Operations
*G. Williams, Associate Manager, Operations

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

NRC Personnel

*T. Farnholtz, Resident Inspector
*R. Haag, Senior Resident Inspector

*Attended exit interview

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

2. PLANT STATUS AND ACTIVITIES

a. The plant operated at approximately 100 percent power during the initial portion of the inspection period until January 27, 1995, when power was reduced to approximately 10 percent and the main generator was taken offline for repair work in the switchyard. Repairs were completed and the main generator was brought back online later that same day. Power was increased to approximately 48 percent to allow repairs to be performed on the main condenser and remained at that level for the remainder of the inspection period.

b. Other NRC inspections or meetings:

Mr. Ellis Merschoff, Director, Division of Reactor Projects, and Mr. Bruce Mallet, Deputy Director, Division of Radiation, Safety and Safeguards, were onsite on January 31, 1995, to meet with resident inspectors, licensee management, and tour the plant.

3. OPERATIONS

a. Plant Operations (71707)

(1) Plant Tour and Observations

The inspectors conducted daily inspections in the following areas: control room staffing, access, and operator responsiveness; operator adherence to approved procedures, TS, and limiting conditions for operations; status of control room annunciators and instrumentation; and review of control room operator logs, operating orders, plant deviation reports, tagout logs, equipment out-of-service log, and tags on components to verify compliance with approved procedures. Routinely, the inspectors attended the operations shift turnover meetings. These meeting which are routinely attended by support personnel were viewed as an excellent means for communicating plant status and ensuring operational needs are clearly understood.

The inspectors conducted weekly inspections for the operability verification 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. The main steam and containment spray systems were included in these inspections.

Plant tours included observation of general plant/equipment conditions, control of activities in progress, plant housekeeping conditions/cleanliness, and missile hazards. 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. Selected tours were conducted on backshifts or weekends.

The inspector reviewed the implementation of Danger Tag 98-0856, which isolated the downstream piping associated with the pressurizer sample line containment isolation valves XVX09356A and XVX09357. Leakage past both of these solenoid operated valves required isolation of the penetration in accordance with TS 3.6.4.c action statement. The inspector verified that the six valves on the Danger Tag would isolate the penetration. The inspector also verified that these valves were in their specified positions, with appropriate tagging installed.

(2) Chill Water (VU) System Review

As part of the licensee's effort to allow cyclic VU chiller operation, various throttled SW flows from the VU chillers were measured and compared with the SW valve position. SW flows and temperatures are the two parameters which must be monitored and established within specified bands to allow cyclic chiller operation. Flows were measured after several valve repositionings to determine the repeatability of specific SW flows based on a given valve position (number of handwheel turns from the full open position). The initial data indicated that SW flow, within a tolerance band, could be obtained from a specific valve position. The inspector reviewed PTP 110.003, determined that personnel were familiar with the procedure requirements, and verified that the system was setup and data collected in accordance with the PTP. Operations management is continuing to review this flow setting method and other options to determine how SW flows will be measured when cyclic chiller operation is implemented. The inspector noted that the SW valve handwheels did not have reference markings to assist in the visual observation required for accurate valve positioning. This was discussed with the licensee.

(3) Reactor Coolant Pump Seal Degradation

During the inspection period, leakage of the No. 2 seal on the "A" RCP increased. The No. 2 seal is a backup for the No. 1 seal. The entire seal package was replaced during refueling outage 8. The normal leakage past the No. 1 seal is three gallons per minute (GPM) most of which is returned to the volume control tank (VCT). Flow indication for this leakage is provided in the control room. Some of the water leaking past the No. 1 seal is used to lubricate and cool the No. 2 seal. This flow is expected to be approximately three gallons per hour (GPH). Leakage past the No. 2 seal is directed to a standpipe which overflows to the reactor coolant drain tank (RCDT). The leakage cannot be read directly but is determined indirectly by monitoring the inleakage into the RCDT. The No. 2 seal appears to be effectively sealing about 75 percent of the time and allowing greater than expected leakage about 25 percent of the time. The result of the degraded seal is that seal No. 1 leakoff flow indication is erratic.

The licensee has issued a station order (SO 95-02), which establishes a minimum No. 1 seal leakoff of 0.2 GPM as measured by flow to the VCT or leakage past No. 2 seal. It also establishes a maximum No. 2 seal leakoff of 1.1 GPM as determined by RCDT inleakage. If these limits are exceeded, preparations for shutting down the RCP are to be made. The leakoff through the No. 2 seal was approximately 0.4 GPM at the end of the inspection period. The leakoff through the No. 1 seal was approximately 2.6 GPM. The low flow alarm setpoint for the No. 1 seal leakoff is 0.8 GPM.

The inspectors have reviewed the licensee's actions with regard to the degraded seal and determined that it is adequate. The sensitivity of the operators on this issue has been raised. The inspectors will continue to monitor this situation closely.

(4) Freeze Protection

The inspector reviewed the heat tracing system and licensee actions as a result of previous equipment freezing problems. The heat tracing control panels and portions of the field heat tracing were walked down to identify problems and assess the overall condition of the heat tracing system. No damage was noted for insulation over the heat tracing or the visible portion of the heat tracing system. Only one recent MWR for a failed indicating light was noted on the heat tracing control panels. While the inspector noted no other operational type problems with the panels, it was noted that the CST heating tracing was not identified on any of the panels. After reviewing this observation, the licensee informed the inspector that heat tracing for safety-related CST components is provided by control panels XPN-2007 and 2008. These panels are labeled as "Reactor Make-Up Water - Unit 4A and 4B". To identify which of the six circuits are for the CST, the heating tracing electrical drawing for the CST must be reviewed. This lack of equipment labeling/identification could hamper timely repair efforts for CST heat tracing problems.

During last winter, freezing occurred with CST level switches and chill water expansion tank surge and supply lines. At the time, temporary heat lights and enclosures were used to correct the freezing conditions. The long term corrective action was assigned to engineering. In a June 29, 1994, engineering review board, this item was discussed. The board recommended that the existing heat tracing setpoints for these applications be raised by 5°F, and that the change be implemented prior to the upcoming winter season. The changes to the setpoints were completed during the first week of January, 1995.

With the exception of some labeling weaknesses, the heat tracing system was being properly maintained. While the licensee's followup actions for previous frozen components were not completed within the prescribed time frame, they have been recently implemented.

b. Onsite Response to Events (93702)

On January 27, 1995, the licensee identified, using thermography, several air disconnects in the switchyard that were operating at a higher than normal temperature. These disconnects were associated with the oil circuit breaker (OCB 8902) located between the main electrical generator and the 230 kV bus. There are a total of six air disconnects associated with this OCB, one for each of the three input phases and the three output phases. The high temperature indications were noted on the three output air disconnects. These disconnects are operated in sets of three (input and output) and were opened during refueling outage 8 for maintenance. To close these disconnects, they are lowered into place, rotated and locked using a handcrank. When they were closed at the end of refueling outage 8, personnel failed to ensure that the disconnects had fully rotated and locked in place. This caused a high resistance connection and the resulting high temperatures.

The repairs to the air disconnects required that the plant be taken offline to allow cleaning and inspecting of the contacts and proper reclosing of the disconnects. The inspectors observed the reduction in power and the opening of the main generator output breaker. These operations were performed in accordance with GOP-4. Reactor power was reduced to approximately 10 percent and the main generator output breaker was opened. Reactor power was stabilized, using steam dumps, at about 10 percent and remained at that level while work in the switchyard was completed. Upon completion of the switchyard work, the main generator was synchronized to the grid and the main output breaker was closed. Power was increased to approximately 48 percent and stabilized for work in the main condenser water boxes involving suspected leaking tubes. The inspectors concluded that the licensee performed these evolutions in a controlled and deliberate manner. Control room communications was good and no significant problems were identified. Management exhibited conservative decision making when taking the unit offline and repairing the disconnects. Failure of the disconnects with the plant at 100 percent power would have resulted in a significant plant transient.

c. Followup - Operations (92901)

(Closed) Violation 395/93-19-01, (LER 93-03) Personnel Error Resulting in the RB Purge System Being Outside the Provisions of Technical Specifications. See paragraph 7 for closure of this item.

(Closed) Unresolved Item 395/94-10-01, Maintaining an Auxiliary Building (AB) Door Open.

The licensee's previous practice was to routinely keep the AB rollup door open, such that air flow into the building would enhance the comfort level in the AB. The inspector questioned this practice and the effects the open door could have on the AB ventilation system. As followup to this item, the licensee added program requirements to keep the door closed when not in use. A sign was placed next to the door informing personnel that the door was to remain closed when the entry way into the building was not in use. Since this requirement was implemented the inspectors have not observed the door being opened unless activities were ongoing in the area.

The licensee maintains that the position of the rollup door is not a safety significant issue since the AB ventilation is classified as nonsafety-related. The fuel handling building ventilation system, which is separate from the AB ventilation, is safety-related and designed to operate during post accident conditions. The open AB door has no affect on the fuel handling building ventilation system. The licensee stated that the AB door would be maintained closed as a good operating practice. The inspector reviewed the FSAR, the ventilation system design basis document, and applicable Regulatory Guides and concluded that the AB ventilation does not have a safety function related design basis accident mitigation.

4. MAINTENANCE

a. Maintenance Observation (62703)

Station maintenance activities for the safety-related and other important 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, 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:

(1) Partial teardown and inspection of diesel generator "B" starting air compressor (P0181099). This was an annual maintenance activity of a non safety-related air compressor which supplies compressed air to the starting air storage tanks. The inspector noted that the technician performing the work had not signed the "prerequisites" and the "limits and precautions" sections of the data sheet as they were completed and before proceeding on to the next section. The safety significance of this is minimal; however, it may indicate a lack of attention to detail.

(2) Diesel generator "B" engine quarterly maintenance (P0183044). This activity consisted of inspection and preventive maintenance tasks. The inspector noted that all 16 air inlet filters were identified as requiring replacement during the inspection and were replaced. These filter elements are visually inspected during this quarterly maintenance activity and monitored during diesel engine operation by two manometers which indicate differential pressure across the filter elements. The filter elements are replaced as required. The inspector considered this monitoring/inspection program to be adequate to identify filter elements which require replacement. Other activities associated with this maintenance activity were also performed as required.

(3) Oil change in the inboard and outboard bearings of the "B" emergency feedwater pump (P0182065). This was a semi-annual preventive maintenance activity. The inspector noted what appeared to be dirt particles in the oil drained from the outboard bearing. The licensee routinely takes oil samples from bearings during oil changes for analysis. The standard analysis performed is ferrography in accordance with Chemistry Procedure, CP-439. The purpose of this analysis is to identify specific types of wear and specific metals that are wearing, which help to identify equipment components that are wearing.

In the case of the "B" EFW pump, the samples were taken as the oil was being drained from the inboard and outboard sumps. In the analysis process, wear particles are precipitated according to size. Large particles are defined as greater than 15 um in size and small particles are less than 15 um. The particles are given a designation, D_L (large) and D_S (small). The sum of the D_L and D_S terms gives a result called the wear particle concentration (WPC). The results for the outboard bearing showed a D_L of 37 and a D_S of 17 for a WPC of 54. The average WPC for this bearing based on historical data is 37. In general, if the WPC of the analyzed sample is greater than two times the average, it would be considered abnormal. The oil lab supervisor reviews the data to determine if further analysis or other action should be taken. The results for the inboard bearing showed a D_L of 5 and a D_S of 4 for a WPC of 9. The average WPC for this bearing is 23.

The inspector considered the licensees oil analysis program to be a strength in that it helps identify abnormal wear at an early stage so that repairs can be made before equipment failure or damage occurs. The standard ferrography analysis; however, only reveals magnetic particles while dirt particles or other contamination are not analyzed. The dirt that was noted by the inspector in the oil drained from the reservoir was not directly analyzed for and, as a result, its origin is unknown. Dirt and contamination in the oil could cause an increase in wear particles which would be detected by the ferrography analysis.

(4) Visual inspection of "C" charging pump motor switchgear (PMTS P0182434). There were no discrepancies noted during this semi-annual preventive maintenance task.

(5) Operational check of "C" charging pump circuit breaker (PMTS P0182472). This is a 7.2 kV General Electric Magna-Blast Breaker. In accordance with the procedure (EMP 405.001), the technicians recorded the reading on the cycle counter to determine how many cycles the breaker had been subjected to since the last maintenance. The technicians noted that the breaker had 496 cycles since the last full PM had been performed. This caused the technicians to expand their task and perform the full PM procedure (EMP 404.013) which is required every 500 cycles. The inspector noted a good knowledge level on the part of the technicians. The task was performed within the program requirements.

(6) Temporary disconnection of the governor valve leakoff line for the emergency feedwater pump turbine (MWR 9404557). The MWR was initially written due to packing leakage from the governor valve. As part of their investigation, engineering directed that the leakoff line be disconnected to allow verification that the line was not clogged. If the line were clogged, it would contribute to packing leakage. Based on verification that the line was not clogged the system engineer stated that the valve repacking task would be scheduled.

(7) Calibration of "B" EDG underground fuel oil storage tank level switch ILS5425 (PMTS P0182355).

(8) Replacement of the diaphragm in the air actuator for steam dump valve IFV2006 (MWR 94I3013). A leak in the diaphragm was noted early while stroking the valve with AOV diagnostic equipment installed on the valve. This was part of a repair effort to properly setup the air actuator to correct minor leakage past the valve seat. Following the diaphragm repair, the inspector observed portions of the actuator setup with the diagnostic equipment. The technicians involved with the setup were knowledgeable of the diagnostic equipment and the different valve parameters that were adjusted/verified.

An indication of inattention to documentation detail was noted during a maintenance activity on a diesel air start compressor. The programs for replacement of diesel air filter and oil analysis were viewed as strengths.

b. Surveillance Observation (61726)

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

(1) Emergency notification public address system test (EPP-104). The licensee maintains two public address speakers at nearby outdoor recreational areas for the purpose of supplying emergency information/instructions to persons using these areas. These public address systems are in addition to the warning sirens located throughout the area and are not required by current NRC regulations. During the test, one speaker (No. 45) failed to operate and corrective actions were initiated.

(2) Main steam valve operability test (STP 121.002). These valves are tested every 92 days in accordance with inservice inspection requirements of the ASME boiler and pressure vessel code and TS 4.0.5. No discrepancies were noted.

(3) Main steam isolation valve (MSIV) partial stroke test (STP 121.002). The purpose of the test was to stroke the MSIV's to approximately 90 percent open to verify valve movement. During the test, air is bled from the valve operator until the valve begins to close under spring pressure. When the valve reaches the 90 percent open position, two valves in the bleed off line close to stop the decrease in air pressure in the valve operator and thereby stopping valve motion. Air pressure in the operator is then raised to return the valve to a full open position. There is a delay between moving the test switch to the test position and the closing of the two vent valves (which indicates that the valve has reached the 90 percent open position).

On the first attempt to perform this test on the "C" MSIV, the operator placed the test switch in the test position and noted the time which elapsed until a green light indicated that the two vent valves were energized to close. The test procedure provides guidance that this time should not exceed 25 seconds. After 25 seconds the green light had not illuminated and the operator returned the test switch to the normal position. Another operator was stationed at the valve to observe actual valve motion and a second attempt was made. The operator performing the test positioned the test switch to the test position. Proper indication and valve movement were noted after a time of 35 seconds.

A test deficiency was noted and a maintenance work request (MWR 9503100) was written. The metering valve, which controls the rate at which air is bled from the valve operator, will be adjusted when the next surveillance test is scheduled to be done in the next quarter. The inspector had no concerns regarding the proposed adjustment since the valve did exhibit proper movement during the test. Discussions with the systems and component engineer indicated a good level of understanding of the test system and of the problem encountered during the test. All other program requirements were met.

(4) Feedwater (FW) flow and steam generator moisture carryover lithium tracer test (PTP 280.003). This test involved the introduction of lithium hydroxide in the FW system upstream of the FW flow venturies. By measuring the concentration of lithium in FW samples taken downstream of the venturies, the amount of FW flow was be calculated. This flow was compared with the indicated FW flow and a determination was made that fouling had not occurred with the venturies, therefore no FW flow adjustments were required. The test results indicated that the moisture carryover was significantly higher than expected for the new S/Gs. The licensee is continuing to review this issue.

The observed surveillance testing was performed satisfactorily and demonstrated that the applicable equipment/system parameters were acceptable.

c. Followup - Maintenance (92902)

(Open) Inspector Followup Item 395/93-24-01, Longstanding Chiller Problems.

The inspector accompanied the system engineer, the mechanical maintenance supervisor and a maintenance technician to examine the "C" VU chiller for its oil discoloration problem. The compressor's lower oil level site glass was dark brown in color and it was not readily discernable by the inspector whether this indicated a full level status or the inside face of the site glass was discolored. Review of the operator's logs for the subject chiller's lower oil level for the week of January 23, 1995, disclosed they recorded full oil levels. Despite following the vendors recommendation of frequent oil changes and site glass replacements when the oil became to discolored to determine its level, the problem still exists. The licensee originally believed the discoloration to be the resultant of a sludge or film formed in the lower oil sump at some past time due to overheating. The licensee now believes the chiller has had the refrigerant charge contaminated with water, and the oil discoloration problem is due to rust.

Due to the change in the licensee's cause determination for the discolored oil, the frequency of oil changes has decreased. From November 19, 1993, to April 7, 1994, the oil was changed four times, with April 7 being the last time the oil was changed. The inspector was concerned that detection of low oil level in the lower sight glass would be difficult with the current conditions of the chiller. An adequate oil level in the chiller as indicated by the lower sight glass is a critical parameter for chiller operation. The inspector accompanied two different operators as they checked the oil level in the lower sight glass. One operator used a flash light while the other operator only looked at the sight glass. The licensee stated that the operators can detect the presence of oil in the sight glass based on their training and experience. Following discussions with the inspector, the licensee stated that they would further review their maintenance program for chiller oil change out.

d. Foreign Material Exclusion (FME) Controls (TI 2515/125)

The temporary instruction provided inspection guidance to determine if effective procedures have been implemented to prevent foreign material from inadvertently entering safety systems during maintenance activities, outages, and routine operations. During the past refueling outage (September - December, 1994), FME and cleanliness controls were reviewed as related to S/G replacement and other outage activities. A violation was issued for inadequate cleanliness control instructions involving S/G secondary side openings. At that time, both the governing cleanliness control procedures and the applicable work instructions were reviewed. The inspector determined that the licensee's cleanliness procedures was general in nature, yet they addressed the various aspects of the FME program. A lack of procedural details and work instructions that vaguely address cleanliness controls contributed to the violation.

As part of the RB close out process, radiological related material such as coverings and step-off pads are removed. During the inspector's tours of the RB, it was verified that these actions and other RB cleanup efforts were properly implemented. The inspectors have also observed appropriate cleanliness controls being used during routine type maintenance activities. A detailed review was completed for the RB sump cleanliness verifications that are required by TS. With the exception of specific inspection steps for the sump grating structural integrity, the licensee's procedures adequately addressed the TS requirements. A followup inspection of the sumps by the inspectors verified, to the extent possible, that the sumps were clean.

Based on a review of the licensee's problem reporting systems, there has only been one recent FME related problem. NCN 5125 documented the discovery of a small package of desiccant in a new CCW valve that had been installed during the outage. The lack of thorough valve inspection prior to installing the valve was the apparent cause of this problem.

Based on previous reviews/inspections, the inspectors concluded that the licensee has an effective program for FME controls and the program requirements are generally implemented properly.

5. ENGINEERING

Followup - Engineering (92903)

(Closed) Unresolved Item 395/94-16-02, Change in Frequency of Turbine Control Valve Testing

Due to increased steam generator tube leakage, the licensee wanted to minimize reactor power changes thereby reducing the possibility of further increases in the leak rate. A reduction in turbine control valve testing frequency from monthly to quarterly was an option to minimize power changes, since power was normally reduced to 90 percent for control valve testing. The licensee completed a 50.59 evaluation for a one time change from the FSAR commitment of monthly control valve testing to quarterly testing. The change to quarterly testing would require no additional testing due to the upcoming plant shutdown for the refueling outage when the steam generators were replaced.

The inspector reviewed the 50.59 evaluation which used the probability risk analysis (PRA) methodology for determining the effects from changing control valve testing frequency. The increased testing frequency for turbine stop and intermediate valves was also factored into the 50.59 evaluation. The PRA review supported the licensee's position that the change in control valve testing does not increase the probability of occurrence of an accident previously evaluated in the FSAR. The inspector concluded that the evaluation was based on valid assumptions and adequately addressed this one time extension in control valve testing.

6. PLANT SUPPORT

a. Plant Support Activities (71750)

During inspection activities and tours of the plant, the inspectors routinely observed aspects of plant support in the areas of radiological controls, physical security, and fire protection. The level of radiological protection controls applied to work activities observed was commensurate with the difficulty and risk associated with the task. Aspects of the fire protection program that were examined included transient fire loads, fire brigade readiness, and fire watch patrols.

Effective implementation of the physical security program continued to be demonstrated during inspector observations of: security badge control; search and inspection of packages, personnel, and vehicles; tours and compensatory posting of security officers; and control of protected and vital area barriers.

b. Fire Detection System Modification

The inspector reviewed the licensee's efforts to upgrade the plant fire detection system. During refueling outage 7 (March - May 1993), the licensee implemented a program to replace the existing fire detection system with a new system. The existing system which was installed in the plant at the time of its construction, consisted of 18 Remote Information Acquisition Control (RIAC) panels installed throughout the plant and connected together with coaxial cable to form a loop. Smoke detectors, installed in zones, were connected to the RIAC panels which in turn was connected to a computer and several display units. The system status could only be determined by looking at one of the display units located in the control building. The manufacturer could no longer supply parts or services for this system since it was obsolete. As a result, the licensee was experiencing reliability problems and difficulty in repairing system components.

The fire detection system selected to replace the existing system consists of two loops or channels with Channel 1 having five cabinets (called 4100 cabinets) and Channel 2 having three 4100 cabinets. Each cabinet in a loop is connected to each other and to a central cabinet (called a 2120 cabinet) with fiber optic cables. A touch screen type display unit is located in the control room along with an additional display unit located in the fire protection officer's office. Smoke detectors are connected, by zones, to the 4100 cabinets which are capable of displaying detector status. System status can be ascertained at the display terminal in the control room. The system is powered from the security inverters with backup batteries located in each cabinet.

During the performance of the modification to change to the new system, both the old and the new systems were in service simultaneously to cover different zones in the plant. The licensee implemented the modification one zone at a time which required rendering the zone inoperable. To compensate for this, the licensee established fire watches until the zone being worked was declared operable on the new system. In some zones, additional smoke detectors and ion detectors (to detect electrical transformer failures) were installed.

Originally, this modification was scheduled for completion by the beginning of refueling outage 8 (September 1994). However, due to budget considerations, the scheduled completion date has been pushed back to the end of 1995. The inspector considered the modification to be a major improvement over the original fire detection system.

Improvements in the areas of reliability, ease of use, and ease of maintenance were noted. The compensatory actions taken by the licensee during the modification process met the requirements of the fire protection program. The inspector was concerned that the delayed implementation of this modification may indicate a lowering of its priority. However, the inspector concluded that this modification is an example of the licensees willingness to upgrade plant systems when it becomes necessary.

c. Control of Security Locks and Keys

The inspectors performed an overall assessment of the program for controlling security locks and keys. Security Plan Procedure, SPP-210, Security Lock and Key Control, was reviewed. The inspector held discussions with security management and security officers as part of the verification that program requirements were being implemented. Also, the inspectors independently verified the following program attributes/requirements:

- The remote security key depositories located throughout the plant were properly locked and sealed. Also, the security key inventory report that is completed each shift requires verification that the seals are intact. The inventory report for January 26, 1995, was reviewed and verified to be properly completed.

- The tag numbers for ten keys located in the primary access portal key depository were verified to be correct, with the correct key designation listed on the inventory report.

- The primary key depository was inspected. The spare keys and locks were properly tagged. The lock and key control register was reviewed and verified to have the required signatures for key issuance. From review of the register, the inspector verified that the annual lock change outs have been performed.

Step 5.5.4, of SPP-210, requires that the key control officer (KCO) conduct a physical inventory of all security locks and keys at least once each 12 months. The inspector reviewed the security key inventory report sheets for the inventory conducted in March and April of 1994. For some keys that were marked as "S/O" (signed out), the inspector noted that there was no documentation that the KCO physically had accounted for all of the keys. The inspector had discussion with the KCO and was provided additional documentation concerning the inventory. Based on this additional information it appears that the KCO physically accounted for all the keys. The licensee noted that improvements in the documentation of the annual inventory would be reviewed.

Overall, the key control program was properly implemented and involved individuals were knowledgeable of the program requirements.

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

(Closed) LER 93-03, Personnel Error Places Purge System Outside the Provisions of Technical Specification.

On June 28, 1993, in response to a RB low pressure alarm, a non-licensed control building operator opened the alternate purge supply valves (PVG-6056, 6057), and started purge supply fan XFN-95 in order to increase RB pressure, despite RMA-2 being out of service. The subject operator performed this evolution without reading the applicable portion of the controlling procedure (SOP 114, Reactor Building Ventilation System) prior to starting the evolution. If the procedure had been used, this event could have been prevented from happening.

Three minutes later the purge supply fan was stopped and the supply valves were closed as required by TS 3.3.2. and SOP 114, when another control room operator noticed this condition. This event had little safety consequences, since it involved only the RB supply portion of the system and no release to the atmosphere occurred.

Although this event appears to be an isolated personnel error, examination of the Management Review Board Meeting (93-03) minutes revealed it was considered important enough to be discussed by the Board, who in turn tasked senior Operations personnel to pass on "lessons learned" from this event to their employees. Discussions with the Acting General Manager of Plant Operations and review of the August 1993 required reading training records disclosed that all operations personnel received training in the importance of proper procedural usage and the circumstances surrounding this event.

(Closed) LER 93-05, Partial Phase "A" Containment Actuation.

On December 3, 1993, during the performance of "B" train Solid State Protection System (SSPS) slave relay testing in accordance with Surveillance Requirement 4.3.2.1, a problem was identified when the slave relay continuity lamps failed to light. A MWR was generated. After reviewing the existing drawings, the troubleshooting plan called for the technician to place the test switch from the "test" position to the "operate" position to verify normal voltage. When the switch was cycled, an unexpected actuation of the slave relays caused a partial Phase "A" containment isolation. Operations personnel immediately contacted the technicians performing the troubleshooting, had them terminate further troubleshooting, and took action to restore the SSPS to its normal alignment.

The subject partial actuation was due to troubleshooting the test circuitry using drawings that did not accurately reflect the present design. A wiring change in the test circuity was performed in 1984 per MRF 20358. The applicable as-built drawings were originally updated correctly for the subject design package, but on a later date the vendor erroneously voided the MRF 20358 drawing changes thereby reverting all drawings to the previous revision. A detailed review was performed to ensure all modifications to the SSPS were properly revised on the impacted drawings. This resulted in revisions being made to three drawings which were reissued. Prior (1984) drawing revisions and approval were handled by the vendor, but current programmatic controls for revisions of these type of documents require SCE&G Design Engineering approval for incorporation of required changes prior to their release. The operability of the SSPS was not affected, since the problem was confined to the test circuitry of the system.

The cause of the initial problem with the test light was the lack continuity of the 15 volt circuit through the test switch. The condition cleared and could not be repeated during further troubleshooting nor during the next surveillance. Discussions with the involved I&C troubleshooting personnel and review of the subject test switch's history disclosed the test light would not energize during the surveillance test conducted in March 1994, and I&C replaced the test switch per MWR 9313377.

7. EXIT INTERVIEW

The inspectors met with licensee representatives (denoted in paragraph 1) at the conclusion of the inspection on February 3, 1995. During this meeting, the inspectors summarized the scope and findings of the inspection as they are detailed in this report. The licensee representatives acknowledged the inspector's comments and did not identify as proprietary any of the materials provided to or reviewed by the inspectors' during this inspection. No dissenting comments from the licensee were received.

Item Number	Status	Description and Reference
93-19-01	Closed	NOV - Personnel Error Places Purge System Outside the Provision of TS (paragraph 3.c).
93-24-01	Open	IFI - Longstanding Chiller Problems (paragraph 4.c).
94-10-01	Closed	URI - Maintaining a Auxiliary Building Door Open (paragraph 3.c).
94-15-02	Closed	URI - Change in Frequency of Turbine Control Valve Testing (paragraph 5).

8. ACRONYMS AND INITIALISMS

AB	Auxiliary Building
AOV	Air Operated Valve
ASME	American Society of Mechanical Engineers
CCW	Component Cooling Water

CST	Condensate Storage Tank
EDG	Emergency Diesel Generator
EFW	Emergency Feedwater
EMP	Electrical Maintenance Procedure
EPP	Emergency Plan Procedure
ESF	Engineered Safety Feature
FME	Foreign Material Exclusion
FSAR	Final Safety Analysis Report
FW	Feedwater
GOP	General Operating Procedure
GPH	Gallons Per Hour
GPM	Gallons Per Minute
I&C	Instrumentation and Control
IFI	Inspector Followup Item
KCO	Key Control Officer
LER	Licensee Event Report
MRF	Modification Request Form
MSIV	Main Steam Isolation Valve
MWR	Maintenance Work Request
NCN	Nonconformance Notice
NOV	Notice of Violation
NRR	Nuclear Reactor Regulation
OCB	Oil Circuit Breaker
PM	Preventive Maintenance
PMTS	Preventive Maintenance Task Sheet
PRA	Probability Risk Analysis
PTP	Preventive Test Procedure
RB	Reactor Building
RCDT	Reactor Coolant Drain Tank
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RIAC	Remote Information Acquisition Control
RMA	Radiation Monitor-Atmospheric
RWP	Radiation Work Permit
S/G	Steam Generator
SOP	System Operating Procedure
SPP	Security Plan Procedure
SPR	Special Report
SSPS	Solid State Protection System
STP	Surveillance Test Procedure
SW	Service Water
TI	Temporary Instruction
TS	Technical Specification
um	Micron
URI	Unresolved Item
VCT	Volume Control Tank
VU	Chill Water
WPC	Wear Particle Concentration