UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-280/94-02 and 50-281/94-02

Licensee: Virginia Electric and Power Company
5000 Dominion Boulevard
Glen Allen, VA 23060

Docket Nos.: 50-280 and 50-281

License Nos.: DPR-32 and DPR-37

Facility Name: Surry 1 and 2

Inspection Conducted: January 2 through February 5, 1994

Inspectors: L W Garner For — 3-7-94
M. W. Branch, Senior Resident Inspector — Date Signed

L W Garner For — 3-7-94
J. W. York, Resident Inspector — Date Signed

L W Garner For — 3-7-94
S. G. Tingen, Resident Inspector — Date Signed

Approved by: G. A. Belisle — 3-7-94
G. A. Belisle, Section Chief, Division of Reactor Projects — Date Signed

SUMMARY

Scope:

This routine resident inspection was conducted on site in the areas of plant status, operational safety verification, maintenance inspections, surveillance inspections, review of plant minor modifications, inservice testing, and action on previous inspection items. While performing this inspection, the resident inspectors conducted reviews of the licensee's backshifts, holiday or weekend operations on January 6, 7, 21, 22, 23, 24, 25 and February 2 and 3, 1994.

Results:

Plant Operations functional area:

Non-cited violation 50-280/94-02-01 was identified for failure to follow fire seal inspection requirements contained in a surveillance procedure (paragraph 3.b).

An Unresolved Item was identified associated with reactor vessel level indication problems that occurred while shutdown (paragraph 3.i).

The magnitude of the Unit 2 turbine runback on January 4 appeared to be excessive and challenged the operators. Their response to the event was good (paragraph 3.c).

The event assessment of the Unit 2 runback was thorough (paragraph 3.c).

The Unit 1 shutdown was well controlled and command and leadership were evident (paragraph 3.e).

The licensee demonstrated their ability to react to the icing conditions at the low level intake structure that occurred on January 19. However, the licensee's cold weather protection program did not anticipate the icing conditions that occurred during extreme cold weather (paragraph 3.f).

Several examples where personnel had to be prompted to initiate station deviation reports for conditions adverse to quality were noted. For the most part, operations has exhibited a very low threshold for station deviations and this recent trend was not typical performance. Operations management is reviewing this issue with operation personnel (paragraphs 5.c and 7).

Operator response to two events indicated an apparent lack of understanding of equipment operation. The first involved a second Unit 2 turbine runback when load was increased above 70% first stage pressure with a runback signal present (paragraph 3.c). The other example involved an unlicensed operator improperly attempting to adjust the #3 emergency diesel generator reactive load. This resulted in briefly operating equipment on the 1-H bus at undervoltage conditions (paragraph 5.c).

Maintenance functional area:

The service water flow test to two Unit 1 recirculation spray heat exchangers was well organized and conducted (paragraph 3.g).

An Unresolved Item was identified for activities involving a pressurizer hydrogen burn (paragraph 3.j).

Rod control performance problems continue to occur. The maintenance performed on the Unit 2 rod control system to troubleshoot and repair the step demand counter indication was efficiently accomplished and there was good communications between operations and instrument and control personnel.

Unit 1 rod control improvements are being implemented and reliability centered maintenance data is being utilized (paragraph 4).

A Unit 1 undervoltage and degraded voltage engineered safety feature actuation surveillance was well coordinated and controlled. A number of equipment problems were noted during the 1-H bus test that required correction and evaluation (paragraph 5.c).

The design change to waterproof the actuator for 1-CW-MOV-106A was accomplished without any deficiencies noted. It was evident that the mechanical and electrical maintenance personnel were prepared to implement this design change (paragraph 6.a).

<u>Engineering functional area:</u>

The procedures developed by engineering support and utilized to accomplish the Unit 1 shutdown worked well, in that, operators did not exhibit significant difficulties in understanding and performing the procedural steps (paragraph 3.e).

The design change packages for implementing minor modifications to valves 1-CW-MOV-106A and 2-SI-MOV-2862B were good quality and were accomplished by maintenance personnel without any significant difficulties encountered (paragraphs 6.a and 6.b).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

* W. Benthall, Supervisor, Licensing
* R. Bilyeu, Licensing Engineer
* H. Blake, Jr., Superintendent of Nuclear Site Services
* R. Blount, Superintendent of Maintenance
* D. Christian, Assistant Station Manager
  J. Costello, Station Coordinator, Emergency Preparedness
* J. Downs, Superintendent of Outage and Planning
* D. Erickson, Superintendent of Radiation Protection
  A. Friedman, Superintendent of Nuclear Training
  B. Hayes, Supervisor, Quality Assurance
*# M. Kansler, Station Manager
* A. Keagy, Nuclear Materials
  C. Luffman, Superintendent, Security
* J. McCarthy, Superintendent of Operations
* A. Price, Assistant Station Manager
  R. Saunders, Assistant Vice President, Nuclear Operations
  E. Smith, Site Quality Assurance Manager
* T. Sowers, Superintendent of Engineering
* J. Swientoniewski, Supervisor, Station Nuclear Safety
* G. Woodzell, Nuclear Training

NRC Personnel

*# M. Branch, Senior Resident Inspector
* S. Tingen, Resident Inspector
  J. York, Resident Inspector

* Attended Exit Interview on February 8, 1994.
# Attended Exit Interview on March 7, 1994.

Other licensee employees contacted included control room operators, shift technical advisors, shift supervisors and other plant personnel.

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

2. Plant Status

Unit 1 began the reporting period in a power coast-down for refueling. The unit was shutdown on January 22 for a planned 64-day refueling outage.

Unit 2 operated at 100% power for most of the inspection period and at the end of the period the unit had been on line for 68 days. On January 4, the unit experienced a turbine runback due to testing on the NI system (see paragraph 3.c). On January 19, power was reduced to 92%

for a short period of time due to icing conditions at the low level intake canal (see paragraph 3.f).

3. Operational Safety Verification (71707, 42700)

The inspectors conducted frequent tours of the control room to verify proper staffing, operator attentiveness and adherence to approved procedures. The inspectors attended plant status meetings and reviewed operator logs on a daily basis to verify operational safety and compliance with TSs and to maintain overall facility operational awareness. Instrumentation and ECCS lineups were periodically reviewed from control room indication to assess operability. Frequent plant tours were conducted to observe equipment status, fire protection programs, radiological work practices, plant security programs and housekeeping. Deviation reports were reviewed to assure that potential safety concerns were properly addressed and reported.

a. Licensee 10 CFR 50.72 Reports

(1) On January 7, the licensee made a non-emergency four-hour 10 CFR 50.72 report due to an ERFCS failure that rendered the SPDS unavailable. The ERFCS failed at 12:20 a.m. and was returned to service at 1:45 a.m. The ERFCS failure occurred when a disk drive malfunction rendered the on-line data processor inoperable, and the standby data processor failed to automatically transfer to the data collection mode of operation. When this condition was identified, personnel manually placed the standby data processor into operation. This restored the ERFCS to an operable condition. The disk drive that had previously malfunctioned was replaced and the data processor was returned to its normal operating mode.

(2) On February 4, the licensee made a non-emergency four-hour 10 CFR 50.72 report due to discovering a potential leakage path from Unit 1 containment. While inspecting the SW piping inside containment, a small hole was found in the piping downstream of recirculation spray heat exchanger 1-RS-E-1B. The unit was in cold shutdown when the hole was identified. Calculations performed by the licensee indicated that the hole could have allowed leakage in excess of that allowed by 10 CFR 50 Appendix J. The hole was scheduled to be repaired prior to restarting the unit from the current RFO.

The inspectors performed an initial assessment of the safety significance of the hole in the SW pipe as it related to containment integrity. The pipe with the through wall leak, formed the membrane barrier between the inside containment atmosphere and the service water. In addition to the membrane barrier the penetration in question was also isolable and was in-fact isolated by closed containment isolation valves. The SW discharge piping is monitored by a radiation monitor that would alert the operators to isolate the RS heat exchanger if necessary. With the one RS heat exchanger isolated, 100% containment heat removal capacity would still be available. At the end of the inspection period the licensee was still evaluating the issue and an LER is scheduled to be issued within the 30 day period. The inspectors continue to follow the licensee's assessment of this item.

b. Unit 1 Cable Vault Fire Barrier Penetration Seals

During a routine walkdown of the Unit 1 cable vault upper section, the inspectors noted that a metal duct was covering a wall area that contained three HS system fire barrier penetration seals. This wall was required to be a 3-hour fire resistance rated barrier in accordance with the Appendix R program. The inspectors questioned if the duct or seals installed around the piping provided the required fire barrier. The inspectors were informed that the penetrations were sealed and that the metal duct was not the design fire barrier.

Because the duct covered the three HS fire barrier penetration seals, the seals were not able to be visually inspected unless the duct was removed. As a result of the inspectors questioning the existence of adequate fire seals, the licensee attempted to inspect the three penetrations without removing the duct. The licensee was unable to verify that the penetration fire seals were installed. The fire barriers were declared inoperable and a fire watch was posted in accordance with TS 3.21.B.7. The duct was then removed, and it was concluded that no fire barrier seals existed in these penetrations. Fire barrier seals were subsequently installed.

TS 4.18.G.1.a requires that fire barrier penetration seals be visually inspected every 18 months. Procedure 0-LPT-FP-001, Fire Barriers, implemented TS 4.18.G.1.a and was last performed in September 1993. The inspectors reviewed the procedure's performance copy dated September 1993, and concluded that the procedure was completed without properly inspecting the three HS fire barrier penetration seals. The licensee indicated that personnel performing the inspections did not properly interpret the fire barrier inspection requirements contained in 0-LPT-FP-001 for inaccessible seals and; therefore, failed to identify that the seals were not installed.

In order to prevent recurrence, the licensee was revising 0-LPT-FP-001 to clarify inspection requirements for inaccessible seals and was planning to provide additional training to personnel that inspect fire seals to ensure that inaccessible seals are properly inspected. At the end of the inspection period, the licensee was developing a program to inspect additional mechanical system fire barrier penetration seals in order to determine if other seals have been properly inspected. The licensee had already implemented an extensive inspection program for electrical penetration fire seals.

The licensee reviewed the Appendix R Report combustible loading analysis for the areas adjacent to the three penetrations and concluded that there was not a significant operability concern. The adjacent areas were classified as less than one minute fire loading zones and therefore would not provide a sufficient concentration of combustibles from any flames, smoke or hot gases generated from a fire. The inspectors' review of the information provided resulted in similar conclusions.

The inspectors concluded that the failure to properly interpret procedure 0-LPT-FP-001 fire seal inspection requirements was a violation of TS 6.4.D which requires that procedures be followed. This was identified as NCV 50-280/94-02-01, Failure to Follow Fire Seal Inspection Requirements. This NRC identified violation is not being cited because criteria specified in Section VII.B of the NRC Enforcement Policy were satisfied.

c. January 4 Unit 2 Turbine Runback

On January 4, Unit 2 experienced a turbine runback from 100% to approximately 51% power. The runback occurred during a special test of power range NI channel N41. This test is designed to gather data to support the September 1994 RFO core reload. The NIS runback began immediately after the I&C technicians connected the test equipment inside the NI drawer. The plant's response to the event was as expected, i.e., the steam dumps opened to control steam pressure and inward rod motion controlled T avg. However, the turbine runback to 51 percent power was excessive and approximately 19 percent greater than designed. The operators started an additional condensate pump and bypassed condensate polishing to ensure adequate MFWP suction pressure. After plant conditions were stable, the operator attempted to increase turbine load to close the steam dump valves. When turbine load increased above 70% another runback to approximately 55% power occurred because the NIS runback signal was still present. This second runback resulted from the operator's lack of understanding of the control logic.

The licensee performed Event Assessment 94-01 to identify the root causes and any corrective actions associated with the event. The inspectors reviewed the assessment which concluded that the NIS runback was caused by a channel N41 failure. The channel failed due to installing test equipment that was not grounded. The channel failed when the control power fuses blew immediately following connecting the test device (recorder) to plant equipment. The assessment concluded that the test equipment was not grounded because the test cart receptacle used to energize the test equipment did not provide an adequate ground. The inspectors concluded that the assessment was thorough. Corrective actions included replacing the test cart receptacle and modifying the method of checking test equipment prior to use. Previously, pieces of test equipment were checked individually prior to installation. Under the new method, the test equipment will be assembled and checked as a unit prior to connection to a plant system.

The assessment also concluded that the turbine ran back 19% further than the design setpoint of 70% of full load. This was previously identified as a recurring problem and was attributed to governor valve operating characteristics. A modification to eliminated this automatic runback feature is scheduled for implementation during the Unit 2 1994 RFO and Unit 1 1995 RFO.

d. Unit 1 Containment Integrity Verification

On January 22, the inspectors verified that containment integrity was not compromised while bleeding steam for temperature and pressure control when the plant was being maintained in hot shutdown. Specifically, the inspectors verified that proper administrative controls were established and maintained while one of the three MSIV bypass valves was unlocked and throttled open. Throttling of the bypass valve provided for fine temperature control by restricting the flow path used to bleed steam to the condenser via the main steam dump valves.

The inspectors noted that adequate administrative controls were implemented by procedures, and that an operator was stationed by the valve with communication to the control room in the event that the valve would have to be closed for containment integrity.

e. Unit 1 Shutdown for RFO

On January 21 and 22, the inspectors witnessed the shutdown of Unit 1 in preparation for the RFO. The unit ramp down rate was 150 MW/HR and the unit was at 53.5 % power when the shutdown was initiated. Procedures involved included 1-GOP-2.1, Unit Shutdown, Power Decrease From Maximum Allowable Power to 25% to 30% Reactor Power, revision 3; 1-GOP-2.2, Unit Shutdown, 25% - 30% Reactor Power to 2% Reactor Power, revision 4; and 1-GOP-2.3, Unit Shutdown, 2% Reactor Power to HSD, revision 3. The inspectors concluded that the shutdown was well controlled and command and control was evident. It was clear that the unit SRO was in charge of the evolution, procedures were followed, and operators continuously self-checked their actions. The procedures, upgraded by engineering support and utilized to accomplish the shutdown, appeared to work well, in that, operators did not exhibit significant difficulties in understanding and performing the procedural steps.

The only time the operators were challenged during the shutdown was when SG level control was transferred from automatic to manual. Although there were several swings in SG levels while in manual control, operators successfully controlled the level in each SG within acceptable limits. This control prevented an automatic reactor trip due to high or low SG level. The inspectors discussed the manual control mode of maintaining SG level with operators and have witnessed similar occurrences during startups and other shutdowns. The inspectors concluded that the feedwater control system's manual operation challenges operators.

f. Problems at Low Level Due to Extreme Cold Weather

On several occasions throughout the inspection period ambient temperatures were significantly below normal. On January 19, ice buildup on the low level intake canal trash racks and rotating screens restricted flow to the suction of the CW pumps. This condition degraded CW performance which made it difficult for operators to maintain intake canal level. As immediate corrective actions, waterbox inlet MOVs were throttled to conserve intake canal inventory and personnel were stationed at the low level intake structure to remove the ice from the rotating screen assemblies. Throttling water box inlet MOVs resulted in the need to reduce Unit 2 reactor power. Intake canal level decreased to 26.2 feet before level was stabilized. Station management manned the TSC in order to coordinate and implement the following actions at the low level intake structure to improve CW performance:

- The upper stop log was installed in the inlet bay to each CW pump.

- Every third basket was removed in each of the rotating screen assemblies.

- The upper rotating screen assemblies were covered with herculite and heaters were placed in the area.

- A tug boat was utilized to break ice at the entrance to the low level intake structure.

- Personnel were stationed at the low level intake structure to monitor conditions.

There were no icing problems at the intake canal high level structure; however, several actions were implemented to prevent any problems from occurring. The upper stop log was installed in each inlet bay and every other basket was removed in each of the rotating screen assemblies. Herculite and heaters were also installed at the rotating screen assembles.

The inspectors concluded that the licensee's response to the icing conditions at the low level intake structure was effective in improving CW pump performance. This action allowed the units to stay on line during a period when the electrical demands forced rotating "black outs" in the service area. The cold weather protection program, implemented several months earlier, had not anticipated the icing conditions that occurred at the low level intake canal on January 19. At the end of the inspection period, the licensee was evaluating revisions to the cold weather protection program to better anticipate extreme cold weather effects on the station.

g. Service Water Flow To Recirculation Spray Heat Exchangers

On January 24, the inspectors observed portions of the SW flow test conducted on the Unit 1 RSHXs 1-RS-E-1B and 1-RS-E-1C. The test was performed in accordance with special test procedure 1-ST-0310, Recirculation Spray Heat Exchanger Service Water Flow, dated January 21, 1994. This test had two purposes: (1) to collect data to verify that design basis accident service water flow was adequate to reject design basis containment heat loads, and (2) to collect data on valves 1-SW-MOV-104B, RS HX B SW INLET and 104C, RS HX C SW INLET, to support GL 89-10 reviews. This test was performed at the same time the J-bus logic test procedure 1-OPT-ZZ-002 was performed.

The inspectors observed part of the test preparations, the pre-job briefing, and reviewed the test procedure. The test was monitored from both the main control room and the Unit 1 safeguards area by the inspectors. Preliminary results identified that the SW flow through both heat exchangers was good and very little, if any, blockage exited. The actual calculations are currently being performed by the engineering organization and will be reviewed by the inspectors. The test was well organized and progressed smoothly. No discrepancies were identified.

h. Contamination of Worker

While inspecting Unit 1 RFO activities, the inspectors reviewed a worker contamination event that occurred on January 27. When a contract worker (welder/rigger), who had been handling deck grating, attempted to exit the containment building, contamination was detected on his hand by the PCM-1. His hand was frisked (8000 cpm) and several decontamination attempts by HP personnel and by medical personnel were unsuccessful. The licensee's doctor placed ointment, bandages and a glove on the worker's hand prior to allowing him to leave the site. The worker was given instruction by HP personnel which included returning to the site for further decontamination efforts. HP continued to monitor the individual and on February 2 the contamination was no longer present. The estimated external extremity dose from the contamination was 703 mrem. The estimated internal dose was less than 0.1 mrem. The inspectors discussed the worker contamination event with Region II radiological protection personnel and they determined that the licensee's actions were appropriate. The NRC's detailed review of this event is documented in NRC Inspection Report Nos. 50-280, 281/94-05.

i. Unit 1 Reactor Vessel Level Indication

At approximately 10:40 a.m. on February 1, the level in the reactor vessel standpipe decreased unexpectedly. Level in the standpipe was initially 18.0 feet and decreased to 16.5 feet over a ten minute period. Operators isolated letdown and initiated makeup to the reactor vessel from the RWST. The containment, auxiliary building and safeguards valve pit were inspected for leakage and no leakage was identified. A reactor vessel level of 16.5 feet is 1.2 feet above the level designated as reduced inventory.

Approximately 15 minutes after the level was noted to be decreasing, Vent/Vent radiation monitors alarmed in the alert range indicating that activity in the containment atmosphere had increased. Air samples obtained from the containment refueling floor indicated that the DAC was 1.3. The DAC prior to this event was 0. The Vent/Vent peak release rate was calculated to be 8.07% of TS.

Level in the reactor vessel was returned to 18 feet and remained stable. The containment was purged and activity in the containment atmosphere returned to normal.

The inspectors monitored refilling of the vessel and reviewed the controlling procedure to verify that level changes and volume changes were as expected. Additionally, the inspectors performed a walkdown of the standpipe assembly to determine if there were any obvious explanations for the indicated level decrease. The inspectors noted that there was a long torturous path from the reactor head to where the vent piping penetrates the pressurizer. The reactor vessel head vent was designed to ensure equal pressure existed between the vented level stand pipe and the vessel. Most of the head vent piping was disconnected at the time of the indicated level drop to allow installation of the cavity seal. However, the vent path described could result in trapping of pockets of water in several areas of the system. The inspectors discussed their observations with the licensee to ensure that the vent path was reevaluated as part of the task teams efforts.

When the event occurred, the reactor vessel head was vented to the containment via an open ended pipe. Personnel in containment noted that water sprayed from the head vent open ended pipe at approximately the same time the reactor vessel level started to decrease. The reactor had been vented to the containment via the open ended pipe for approximately 24 hours previously and reactor vessel level indication was stable. There were no obvious perturbations at the time of the event that could have resulted in a decreasing reactor vessel level. The licensee appointed a task team to investigate this event. The task team concluded that the most probable cause for the inaccurate standpipe level indication was a restriction in the reactor head vent piping. Subsequent to the inspection period, testing performed was unable to verify that this conclusion was correct.

During the last Unit 1 RFO, a similar decrease in reactor vessel level occurred when the reactor head was detensioned. Troubleshooting performed at that time did not identify any blockages in the reactor vessel standpipe assembly. This event and other reactor vessel level indication problems were discussed in NRC Inspection Report Nos. 50-280, 281/92-07.

The reactor vessel standpipe assembly is the sole reactor vessel level indication utilized when the reactor vessel water level is maintained below the reactor head flange. It should be noted that there is another level monitor installed as discussed in Generic Letter 88-17, Loss of Decay Heat Removal. However, this monitor is only used during mid-loop operations since it's range is from the top of the loop piping to the bottom of the loop piping. This second monitor would be off-scale high during operations above mid-loop as was the case described above.

As indicated above, problems with the Unit 1 reactor vessel standpipe assembly indication continue to occur. Incorrect standpipe level indications could result in an unplanned entry into a reduced inventory condition or a loss of shutdown cooling. This concern was discussed with licensee management. At the end of the inspection period, the licensee was developing a strategy to identify the cause of the reactor vessel level problems. Until the problem's root cause is identified and corrections actions are taken, this item will be identified as URI 50-280/94-02-02, Review Reactor Vessel Level Problem.

j. February 3 Unit 1 Pressurizer Hydrogen Ignition

On February 3, 1994, at approximately 2:38 a.m., spikes were observed on the pressurizer level instruments. At the same time, a loud rumbling sound was heard in containment. The containment vent radiation alarm was received and containment was evacuated.

At the time of the event, the pressurizer was drained and vented via open filtered pipes to the containment atmosphere. Apparently pressure fluctuations inside the pressurizer caused radioactive gases inside the pressurizer to be expelled into containment. The highest radiation monitor readings on the containment monitor was 3300 counts per minute and a reading of 8,500 microcurie per second was noted on the Vent/Vent monitor. This Vent/Vent level was estimated to be approximately 30% of TS limits. One worker received an estimated 7 mrems internal exposure and a total dose of 16 mrems.

The cause of the pressurizer pressure increase was investigated by both the licensee and the inspectors. The inspectors interviewed workers involved and conducted an independent inspection of the pressurizer head area. The inspectors noted that the FME screens that were taped over the pressurizer side of the piping where the three safety valves were removed were discolored and appeared burned. Discussions with the licensee indicated that they were investigating a possible cause that involved a hydrogen gas burn inside the pressurizer. A modification to eliminate the pressurizer loop seals was in progress. Welding activities associated with the modification may have ignited hydrogen gas that had come out of solution and accumulated inside the pressurizer and associated piping.

The licensee initiated DR S-94-0263 to document this occurrence. Additional controls for welding on the primary system were also imposed. These required measuring for explosive gases prior to initiating an arc. The licensee's initial investigation also included determining if similar events had occurred at other nuclear facilities. On the afternoon of February 3, after reviewing the preliminary information that was submitted, SNSOC determined that a hydrogen burn had occurred. The SNSOC also determined that the event was not reportable based on a review of their emergency plan and 10 CFR 50.72 and 50.73. However, a voluntary LER will be submitted to alert the industry of the occurrence.

The inspectors continue to follow the licensee's investigation and root cause determination of this event. This item is identified as URI 50-280/94-02-03, Evaluation of Pressurizer Hydrogen Burn. Issues that need resolving included, determining the source of the hydrogen since the RCS had been degassed to < 4 cubic centimeters/Kilogram during the plant shutdown/cooldown evolutions. Additionally, welding procedures were being reviewed to determine why there were no precautions to monitor for explosive gases prior to welding on the RCS. The licensee was also considering utilizing industry data to evaluate the pressurizer stresses associated with this event.

Within the areas inspected, one non-cited violation was identified.

4. Maintenance Inspections (62703, 42700)

During the reporting period, the inspectors reviewed the following maintenance activities to assure compliance with the appropriate procedures.

Rod Control Activity

Unit 2 shutdown bank B group 2 step demand counter was identified to be malfunctioning while performing a routine control rod exercise surveillance test on January 26. Operators noted that upon releasing the rod motion lever, the step demand counter indicated that shutdown bank B group 2 rods continued to move inward one extra step. On that same day the shutdown bank B group 1 and 2 step demand counter driver card was replaced and shutdown bank B rods were exercised. During the exercise, the group 2 rod step demand counter continued to indicate that rods moved inward one additional step when the rod motion lever was released. In addition, the group 1 rod step demand counter indication malfunctioned during the exercise. The group 1 rods were inserted to 212 steps and then withdrawn. The step demand counter indicated properly during rod insertion but remained at 212 steps when rods were withdrawn. The plant process computer, which provides redundant group 1 movement demand indication, and the IRPIs indicated that rod motion occurred as required.

Prior to performing corrective maintenance on January 28, the SNSOC convened to approve the work instructions. The inspectors attended the SNSOC meeting. During the meeting, the maintenance department presented detailed troubleshooting instructions that included installing test equipment to monitor logic cabinet and step demand counter performance and replacing the shutdown bank B step demand driver card. SNSOC did not approve these troubleshooting instructions because a less intrusive method of repair/troubleshooting was desired. SNSOC concluded that replacing the step demand driver card and group 2 step demand counter was a more prudent course of action.

On January 28 the inspectors witnessed replacing the shutdown bank B group 2 step demand counter and shutdown bank B group 1 and 2 step demand counter driver card. This maintenance was accomplished in accordance with troubleshooting WO 281688 and procedure 0-ICM-RD-CAB-001, Rod Control System Power Cabinet and Logic Troubleshooting and Maintenance, revision 0. The inspectors noted that the maintenance was efficiently accomplished and communications between operations and I&C personnel were good. An I&C supervisor, maintenance engineer and training instructor assisted the I&C technicians performing this maintenance.

Following replacement of the components, all control rods were exercised in accordance with 2-OPT-RX-005, Control Rod Assembly Partial Movement. During this test, the shutdown bank B group 2 step demand counter indicated correct rod movement. However, the group 1 step demand counter continued to indicate 212 steps when rods were withdrawn to 225 steps. At the end of the inspection period a vendor representative was providing site support for the licensee's continued review and corrective actions for this malfunction.

TS 3.12.E.1.a indirectly addresses the operational requirements for rod step demand counters and states that above 50% power, the IRPI system shall be operable and capable of determining the control rod positions to within twelve steps of their respective group step demand counter indications. The inspectors noted that when the group step demand counters did not provide proper indication or were deenergized for maintenance either process computer indication for group 1 rods was utilized or control rods were rendered immovable but still trippable and a 2 hour LCO was entered in accordance with TS 3.12.C.3.

Recurring rod control problems are being reviewed by the licensee as a station level one priority. The inspectors attended a meeting where the system engineer made proposals to station management to correct some of the more frequent problems. A plan for Unit 1 rod control improvements was discussed which included RCM recommendations as well as component replacement based on industry NPRDS failure history.

The inspectors observed I&C personnel performing Unit 1 rod control card inspection and replacement. The inspectors were shown several firing cards that were replaced because of heat damage and loose soldered components. Based on the observed card conditions, their replacement was warranted. When combined with other card inspections and component replacements, rod control system reliability improvements were expected by the licensee.

Within the areas inspected, no violations were identified.

5. Surveillance Inspections (61726, 42700)

During the reporting period, the inspectors reviewed surveillance activities to assure compliance with the appropriate procedures and TS requirements.

a. Unit 1 Control Rod Test

On January 13, from the control room the inspectors witnessed operability test of the control rod assemblies' drive mechanisms and control circuits. This test was performed biweekly using procedure 1-OPT-RX-005, Control Rod Assembly Partial Movement, revision 1, dated January 12, 1994. The inspectors observed the reactor operators manually moving the rods 12 steps, recording the position of the rods, and observing that the appropriate alarms were activated. At the termination of the test, a documentation review was made. No discrepancies were identified.

b. Chilled Water Pump A IST

On January 14, the inspectors witnessed testing the A chilled water pump in accordance with 0-OPT-VS-001, Control Room Air Conditioning System Pump and Valve Inservice Testing, revision 5. The purpose of this test was to place the A chilled water pump into service at a specified flow rate and measure pump vibration and differential pressure. The testing results indicated that the pump operated satisfactorily. The inspectors monitored this testing from MER 3, MER 5, and the control room. The inspectors verified that the instrumentation used to obtain test data was calibrated and the procedure was followed. No discrepancies were identified.

c. Unit 1 J-Bus and H-Bus Logic Testing

On January 24, the inspectors witnessed portions of the Unit 1 J-Bus logic testing as specified in procedure 1-OPT-ZZ-002. The test consisted of two basic parts. The first was a simulated high-high containment pressure initiated SI. This part was followed by a simulated loss of off-site power. During the LOOSP portion of the test the running EDG picked up the emergency bus electrical loads and powered the bus while selective ESF loads sequenced back onto the bus. The test was well coordinated and the pre-evolution briefing was extensive and well articulated.

The inspectors monitored the control room portion of the test as well as communications between the test director and the many data gathering stations in other areas of the plant. Several equipment problems were noted and documented on DRs including S-94-0136 for the tripping of 1-VS-F-58A which was not an expected action based on system alignment for the test. Additionally, the inspectors noted that while the 1-J bus was being powered solely by the #3 EDG the unlicensed operator created a low voltage condition on the bus while attempting to adjust VARs. Step 6.4.8 of procedure 1-OPT-ZZ-002 required that a voltage between 4000 and 4400 Vac be maintained by the EDG and for the operator to adjust if necessary. The operator attempted to adjust the VAR reading by lowering the voltage regulator setting. With the EDG as the sole source of power to the bus, this action did not regulate VAR loading; however, it did result in a low voltage condition. The licensed operator in the area noted the condition and voltage was returned within the specified values.

The inspectors expected a DR to be written on the above low voltage condition but, after several days, one had not been written. The inspectors informed the SNS supervisor responsible for the DR system that per VPAP-1501, Station Deviation Reports, the observed condition would meet the threshold for a DR to be written. On January 27, DR S-94-0169 was written to document the occurrence and evaluate the impact of the undervoltage condition on plant equipment that was energized from the 1-J bus. This was identified to licensee management as an example of where Operations threshold for documenting conditions adverse to quality may need adjusting. Discussions with the SNS supervisor revealed that their review of recent events had also identified the possibility of a negative trend in DR identification. Operation management held discussions with their personnel and the inspectors will continue to monitor this area.

The 1-H bus testing was monitored on January 25 and during that test a number of equipment problems were noted and documented on DRs. Examples of the items identified include the following: 1) DR S-94-0148, Terminal 112 inside UPS 1A2 was glowing red; 2) DR S-94-151, Containment isolation valve 1-DA-TV-100A did not indicate fully closed; 3) DR S-94-152, Containment isolation valve 1-CC-TV-105A failed to close and would not close with push-button; 4) DR S-94-150, Breaker for Recirculation Spray pump 1-RS-P-2A did not close when it was sequenced back on the bus following the undervoltage test; and 5) DR S-94-153, Breaker for SW valve 1-SW-MOV-102A tripped on thermal overload. These conditions were noted on the test procedure discrepancy list as well and will require resolution prior to the satisfactory completion of the surveillance test before unit restart.

Within the areas inspected, no violations were identified.

6. Review of Plant Minor Modifications (37828)

a. Modification to Waterproof Unit 1 MOV Operator

The inspectors monitored portions of DCP 93-17, Modify CW Limitorque Motor Operators-Submersible/Surry/Units 1 and 2. The purpose of this design change was to modify the eight condenser CW inlet MOV actuators to make them watertight. Watertight actuators would enhance MOV operation if these actuators were to become submersed in water during a turbine building flood. The inspectors witnessed the modifications implemented by the design change and the testing associated with 1-CW-MOV-106A. This design change was accomplished by WO 266884, Procedure 0-MCM-0305-01, Limitorque Size SMB-0 Through SMB-4 Overhaul, revision 5 and DCP 93-17.

This modification involved replacing several actuator gaskets and O-rings, installing RTV on the actuator's motor end bell joint and fasteners, and installing electrical quick disconnect fasteners at the power leads to the actuator. Following reassembly, an air drop test was performed in accordance with 0-NAT-M-004, Generic Hydrostatic/Pneumatic Test Procedure, revision 1. The actuator was pressurized to 4.5 psig and the acceptance criteria was that pressure could drop no more than 0.5 psig within one hour. The actuator failed the initial air test. Several minor leaks were identified and repaired. Following these repairs the actuator was satisfactorily tested. The MOV was also satisfactorily stroked timed and diagnostically tested.

The inspectors noted that this design change was accomplished on 1-CW-MOV-106A without any deficiencies noted. It was evident that the mechanical and electrical maintenance personnel were prepared to properly implement this design change.

b. Modification to Increase Unit 2 MOV Operator Torque Output

The inspectors witnessed changing the motor and worm gear shaft gears on Unit 2 MOV 2-SI-MOV-2862B. The licensee's GL 89-10 review identified that during a combination of high ambient temperature and reduced voltage, the overall gear ratio of the motor operator did not produce the desired torque. Based on this review, the motor operator gear set was replaced with gears that produced a higher operator torque output. This modification also resulted in a slower stroke time.

This modification was accomplished in accordance with DCP 92-83-3, Misc Limitorque Motor Operator MODS/Surry/1&2, revision 5; Procedure 0-MCM-0304-02, Limitorque SMB-00 Overhaul, revision 3; 0-ICM-15050-01, Limitorque SMB Operator Disconnect and Connect, revision 1; and WO 280451. The inspector attended the SNSOC meeting that approved this design change and safety evaluation, monitored portions of the motor operator gear set replacement and witnessed portions of the post modification testing.

Prior to disassembling the actuator, a torque wrench was utilized to operate the MOV in order to determine the torque required to operate 2-SI-MOV-2862B. The testing results identified that it took less than 25 ft-lbs of torque to operate the quarter turn plug valve. Vendor information on this valve stated that approximately 40 ft-lbs of torque was required to operate the valve. The licensee concluded that 40 ft-lbs of torque applied to a new valve, and as it aged, less torque was required. In addition, 2-SI-MOV-2862B had been satisfactorily stroke tested on a quarterly basis. The valve history indicated that there were no operational problems associated with the valve. The licensee concluded that 2-SI-MOV-2862B was operational prior to implementing the design change. The inspectors agreed with the licensee's conclusion that the valve was operable. The inspectors concluded that the design change package adequately implemented the modification to 2-SI-MOV-2862B.

Within the areas inspected no violations were identified.

7. Unit 1 Inservice Testing

On January 22, the inspectors witnessed/reviewed portions of two 10-year ISI pressure tests. ASME Code Section XI, requires that every 10 years piping systems be hydrostatically tested to determine integrity. The licensee substituted the pressure test for the hydrostatic test required by the code by invoking ASME Code Case N-498. The NRC endorsed this Code Case through revision 9 of Regulatory Guide 1.147; Inservice Inspection Code Case Acceptability, ASME Section XI Division 1.

The first test witnessed by the inspectors was a VT-2 visual inspection of two sections of SI piping located in the Auxiliary Building between valves 1-SI-150 and 1-SI-174 and their respective containment penetrations. The stated test pressure was 2135 psig with the normal system operating pressure being 2235 psig. While performing the test, the actual pressure obtained through throttling the manual valves was approximately 2500 psig based on the local gage. This was due to the sensitivity of the manual valves. The inspectors questioned the adequacy of the test pressure and concluded that it was satisfactory.

The second test reviewed by the inspectors was a four-hour system pressure test of the excess let-down heat exchanger. The inspectors noted through a review of the operators logs that approximately 39 minutes after the excess let-down heat exchanger was pressurized with RCS fluid, radiation monitors 1-CC-RM-105 and 106 went into an alert alarm indicating a possible tube leak. This heat exchanger had been suspected as leaking in the past and was only used whenever the normal let-down path was isolated. The inspectors questioned the licensee as to whether this leak would cause the component to fail the system pressure test. The inspectors reviewed the completed copy of the pressure test procedure and found no mention of the indication of the tube leakage.

The inspectors reviewed the applicable ASME Code Section XI requirements and determined that heat exchanger tube leakage would be rejectable. Note 6 of the licensee's Section XI program stated that visually inspecting the heat exchanger tubes was not required. However, note 6 also stated, "Good Engineering Practices will continue to be followed when the need is recognized". The inspectors recognize that the system pressure test of the excess let-down heat exchanger was not structured to identify tube leakage. However, "good engineering practice" should have required that the noted RCS leakage into the CC system be evaluated and corrected. On January 27, five days after the occurrence and after discussion with the inspectors, the licensee initiated DR S-94-0168 to document the event. This was identified as another example of operators' inappropriate threshold for problem identification and was discussed with the Superintendent of Operations. WO 262027 scope was expanded to investigate and repair the tube leakage prior to unit restart.

8. Action on Previous Inspection Items (92701)

(Closed) IFI 50-280, 281/92-17-01, Gas Void Long-Term Corrective Action. In July 1992, the licensee identified gas voids in the LHSI piping. Immediate corrective action involved venting the LHSI piping. The licensee replaced cold leg check valve 2-SI-85 during the 1993 Unit 2 spring RFO and modified procedure 2-PT-18.11, Cold Shutdown Test of SI Check Valves to Hot and Cold Legs, to ensure that the SI system was properly filled and vented. The inspectors reviewed the 1993 results of procedure 2-OSP-SI-001, Venting SI Piping, which was performed quarterly. The review results indicated that gas had not been identified in the Unit 2 SI piping since the 1993 Spring RFO.

Within the areas inspected, no violations were identified.

9. Exit Interview

The inspection scope and findings were summarized on February 8 and March 7, 1994, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results addressed in the Summary section and those listed below.

Item Number	Status	Description (Paragraph No.)
NCV 50-280/94-02-01	Closed	Failure To Follow Fire Seal Inspection Requirements (paragraph 3.b).
URI 50-280/94-02-02	Open	Review Reactor Vessel Level Problem (paragraph 3.i).
URI 50-280/94-02-03	Open	Evaluation of Pressurizer Hydrogen Burn (paragraph 3.j).
IFI 50-280, 281/92-17-01	Closed	Gas Void Long-Term Corrective Action (paragraph 8).

Dissenting comments were not received from the licensee. Proprietary information is not contained in this report.

10. Index of Acronyms and Initialisms

ASME	AMERICAN SOCIETY OF MECHANICAL ENGINEERS
CC	COMPONENT COOLING
CFR	CODE OF FEDERAL REGULATIONS
CPM	COUNTS PER MINUTE
CW	COOLING WATER
DAC	DERIVED AIR CONCENTRATION
DCP	DESIGN CHANGE PACKAGE
DR	DEVIATION REPORT
ECCS	EMERGENCY CORE COOLING SYSTEM
EDG	EMERGENCY DIESEL GENERATOR
ERFCS	EMERGENCY RESPONSE FACILITY COMMUNICATION SYSTEM
ESF	ENGINEERED SAFETY FEATURE
FME	FOREIGN MATERIAL EXCLUSION
GL	GENERIC LETTER
HR	HOUR
HP	HEALTH PHYSICS
HQ	HEADQUARTERS
HS	HEATING STEAM
HSD	HOT SHUTDOWN
HX	HEAT EXCHANGER
I&C	INSTRUMENTATION AND CALIBRATION
IFI	INFORMATION FOLLOWUP ITEM

IRPI	INDIVIDUAL ROD POSITION INDICATION
ISI	INSERVICE INSPECTION
IST	INSERVICE TESTING
LCO	LIMITING CONDITIONS OF OPERATION
LER	LICENSEE EVENT REPORT
LHSI	LOW HEAD SAFETY INJECTION
LOOSP	LOSS OF OFFSITE POWER
MER	MECHANICAL EQUIPMENT ROOM
MFWP	MAIN FEEDWATER PUMP
MOV	MOTOR OPERATED VALVE
MREM	MILLI-ROENTGEN
MSIV	MAIN STEAM ISOLATION VALVE
MW	MEGAWATTS
NCV	NON-CITED VIOLATION
NI	NUCLEAR INSTRUMENTATION
NIS	NUCLEAR INSTRUMENTATION SYSTEM
NPRDS	NUCLEAR PLANT RELIABILITY DATA SYSTEM
NRC	NUCLEAR REGULATORY COMMISSION
PCM	PERSONNEL CONTAMINATION MONITOR
PSIG	POUNDS PER SQUARE INCH GAUGE
PT	PERIODIC TEST
RCS	REACTOR COOLANT SYSTEM
RFO	REFUELING OUTAGE
RM	RADIATION MONITOR
RS	RECIRCULATION SPRAY
RSHX	RECIRCULATION SPRAY HEAT EXCHANGER
RTV	ROOM TEMPERATURE VULCANIZER
RWST	REFUELING WATER STORAGE TANK
SG	STEAM GENERATOR
SI	SAFETY INJECTION
SNS	STATION NUCLEAR SAFETY
SNSOC	STATION NUCLEAR SAFETY AND OPERATING COMMITTEE
SPDS	SAFETY PARAMETER DISPLAY SYSTEM
SRO	SENIOR REACTOR OPERATOR
SW	SERVICE WATER
T AVG	AVERAGE TEMPERATURE
TS	TECHNICAL SPECIFICATION
TSC	TECHNICAL SUPPORT CENTER
UPS	UNINTERRUPTIBLE POWER SUPPLY
VAC	VOLTS - ALTERNATING CURRENT
VAR	VOLTS-AMPERE, REACTIVE
VPAP	VIRGINIA POWER ADMINISTRATIVE PROCEDURE
WO	WORK ORDER