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

Report Nos.: 50-280/91-14 and 50-281/91-14

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: May 12 through June 8, 1991

Inspectors: 7/8/91
W. E. Holland, Senior Resident Inspector Date Signed

7/8/91
M. W. Branch, Senior Resident Inspector Date Signed

7/8/91
J. W. York, Resident Inspector Date Signed

7/8/91
S. G. Tingen, Resident Inspector Date Signed

Accompanying Personnel: B. Buckley, Senior Project Manager, NRR

Approved by: M V Sinkule for 7/8/91
P. E. Fredrickson, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine resident inspection was conducted on site in the areas of plant operations, plant maintenance, plant surveillance, licensee event report closeout, and licensee self assessment capability. During the performance of this inspection, the resident inspectors conducted review of the licensee's backshift or weekend operations on May 13, 15, 16, 19, 21, 22, 26, 28, 31, June 1, 2, 5, and 7.

Results:

In the safety assessment/quality verification functional area, one example of a violation was identified for failure to provide adequate instructions and/or procedures when implementing a revision to TS 3.11 regarding waste gas decay tank H_2/O_2 limitations. A similar North Anna problem occurred in March, 1991,

and the resultant corrective actions could have prevented this violation. (paragraph 3.a)

In the operations functional area a continuing strength was identified regarding operator attention to detail and sensitivity to plant conditions and reactivity management during the Unit 2 startup. Good communications and selfchecking techniques were frequently observed between operations personnel. (paragraph 3.b)

In the engineering/technical support functional area, an additional example of the violation for failure to provide adequate instructions and/or procedures was identified. This involved a failure to implement safety analysis assumptions contributing to a Unit 1 reactor load increase above licensed power limits. (paragraph 3.c)

In the maintenance/surveillance functional area, a weakness was identified regarding previous corrective actions, associated with air lock deficiencies, being ineffective in correcting material condition problems of the equipment. (paragraph 3.d)

In the safety assessment/quality verification functional area a strength was identified regarding the licensee making available a second means of level indication for reduced inventory operations ahead of their commitment and prior to entry into reduced inventory condition. This action demonstrated a positive sensitivity to safety. (paragraph 3.g)

In the safety assessment/quality verification functional area, a violation associated with the seal head tank low level alarms was identified for failure to promptly identify and correct conditions adverse to quality (paragraph 5.a).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

R. Allen, Supervisor, Shift Operations
* W. Benthall, Supervisor, Licensing
* R. Bilyeu, Licensing Engineer
* R. Blount, Supervisor, Station Procedures
* D. Christian, Assistant Station Manager
J. Downs, Superintendent of Outage and Planning
D. Erickson, Superintendent of Health Physics
* R. Gwaltney, Superintendent of Maintenance
M. Kansler, Station Manager
T. Kendzia, Supervisor, Safety Engineering
* J. McCarthy, Superintendent of Operations
* A. Price, Assistant Station Manager
* H. Royal, Supervisor, Nuclear Training
* E. Smith, Site Quality Assurance Manager
* T. Sowers, Superintendent of Engineering

NRC Personnel

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

* Attended exit interview.

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 power operation. The unit operated at or about 100% power for the duration of the inspection period. However, on June 6, 1991, reactor power was reduced to approximately 93% when the unit experienced turbine control problems. This item is further discussed in paragraph 3.c.

Unit 2 began the reporting period in refueling shutdown (day 45 of a scheduled 67 day refueling/maintenance outage). During this period the unit entered reduced inventory conditions for approximately four days to conduct maintenance activities on safety injection check valves. This item is further discussed in paragraph 3.g. Also the unit completed

refueling/maintenance evolutions and Type A containment testing. The unit exited cold shutdown conditions on May 31 and had reached hot shutdown conditions when identified leakage greater than TS allowable limits were identified. A UE was declared and the unit returned to cold shutdown to correct the leakage problem. This issue is further discussed in paragraph 3.f. Corrective actions were completed and the unit commenced heatup from cold shutdown on June 4. The unit was taken critical on June 5 and physics testing was conducted over the next 24 hours. The unit was connected to the grid on June 7. However, approximately 25 minutes after connection, an electrical problem in the switchyard occurred resulting in opening of an electrical breaker in the yard. This problem is further discussed in paragraph 3.b. After the electrical problem was corrected, the unit was reconnected to the grid on June 7 to continue startup testing and was operating at approximately 30 percent power when the inspection period ended.

3. Operational Safety Verification (71707 & 42700)

a. Daily Inspections

The inspectors conducted daily inspections in the following areas: control room staffing, access, and operator behavior; operator adherence to approved procedures, TS, and LCOs; examination of panels containing instrumentation and other reactor protection system elements to determine that required channels are operable; and review of control room operator logs, operating orders, plant deviation reports, tagout logs, temporary modification logs, and tags on components to verify compliance with approved procedures. The inspectors also routinely accompanied station management on plant tours and observed the effectiveness of their influence on activities being performed by plant personnel.

On May 24, during routine review of operator logs, the inspectors noted that the following information was recorded with regards to concentrations of oxygen and hydrogen in the waste gas holdup tanks. On May 24, at 0025 hours, routine sample results of the A WGDT revealed that the oxygen and hydrogen concentrations exceeded the TS limits. The A WGDT oxygen concentration was 8.6%, and the hydrogen concentration was 4.6%. TS 3.11.A.1 states that the concentration of oxygen in the waste gas holdup system shall be limited to 2% by volume when the hydrogen concentration exceeds 4% by volume. TS 3.11.A.1.a states that with the concentration of oxygen in the waste gas holdup system greater that 2% by volume but less than or equal to 4% by volume, and the hydrogen concentration greater than 4% by volume reduce the oxygen concentration to the required limits within 48 hours. TS 3.11.A.1.b states that with the concentration of oxygen greater than 4% by volume immediately suspend all additions of waste gases to the affected tank and reduce the concentration of oxygen to less than or equal to 4% by volume.

A backup sample of a WGDT A on May 24, 1991, confirmed that the oxygen and hydrogen concentration level exceeded the TS limits. Operators suspended all additions of waste gases to A WGDT, made preparations to release the tank in accordance with procedure OP-23.2.3, Placing 1-GW-TK-1A On Bleed, dated February 8, 1990. Prior to releasing the A WGDT, operators determined that OP-23.2.3 needed to be revised and decided to wait until day shift to revise the procedure. The procedure was revised on day shift and at 0946 hours, operators initiated the release of the A WGDT. The following day, May 25, at 1448 hours the A WGDT oxygen and hydrogen concentration levels were within the TS limitations. The release of the tank was then secured and the TS LCO exited.

The inspectors reviewed the licensee's actions and considered that the actions did not meet the requirements of TS 3.11.A.1.b because action was not taken immediately to reduce the concentration of oxygen in the A WGDT to less than 4% by volume. It took approximately 38 hours to reduce the oxygen concentration to less than 4% by conducting a long tank drain prior to actually reducing the oxygen concentration with nitrogen. Only several hours are necessary to reduce the concentration, if the nitrogen addition is conducted at the beginning of the evolution.

A primary contributor to this problem was a TS amendment effecting this activity. TS 3.11.A, Explosive Gas Mixture, was amended on April 17, 1991. This new amendment required immediate action be taken when WGDT oxygen and hydrogen concentrations exceeded 4% by volume. The old TS 3.11.A allowed 48 hours to reduce the oxygen concentration to less than 4% by volume. The inspectors concluded that the licensee did not develop an adequate plan to correctly implement the requirements of TS 3.11.A.1.a and 3.11.A.1.b when the TS 3.11 amendment was approved. As a result, procedures and instructions were not in place to immediately reduce the A WGDT hydrogen/oxygen concentrations on May 24.

10 CFR 50, Appendix B, Criterion V, requires that activities affecting quality be prescribed by documented instructions or procedures of a type appropriate to the circumstances and shall be accomplished in accordance with instructions, or procedures. The failure to provide adequate instructions and/or procedures when implementing the revised TS 3.11 is identified as one example of a Violation, 50-280,281/90-10-01, Inadequate Implementation of a Waste Gas Decay Tank TS. North Anna had a similar problem in March 1991 where releasing the tank contents, instead of purging with nitrogen, was used in an attempt to reduce the concentration.

During review of the waste gas problems described above, the inspectors noted that tank sampling was necessary as a compensatory measure because the H2/O2 monitors were not operable. TS 3.7-2.E for the explosive gas monitoring instrument requires that the equipment have an alarm/trip setpoint set to ensure that the limits

of TS 3.11.A.1 are not exceeded. The actions for inoperable monitoring instrumentation requires that a grab sample be taken at least once per 24 hours and analyzed within the following 4 hours. The inspectors observed that grab samples were being taken at approximately 12-hour intervals. Even with this increased sample frequency, though, on four occasions during the inspection period, the samples were in the range that required entry into TS 3.11.A.1 LCOs. Since the purpose of the grab samples was to compensate for inoperable instrumentation and to ensure that the TS 3.11 limits were not exceeded, the inspectors questioned as to whether the licensee had considered further increasing the sample frequency. Discussions with station management on this issue resulted in implementation of a policy to review sampling frequency and increase the frequency based on sample results.

b. Weekly Inspections

The inspectors conducted weekly inspections in the following areas: operability verification of selected ESF systems by valve alignment, breaker positions, condition of equipment or component, and operability of instrumentation and support items essential to system actuation or performance. Plant tours were conducted which included observation of general plant/equipment conditions, fire protection and preventative measures, control of activities in progress, radiation protection controls, physical security controls, missile hazards, and plant housekeeping conditions/cleanliness. The inspectors routinely noted the temperature of the AFW pump discharge piping to ensure increases in temperature were being properly monitored and evaluated by the licensee.

During this period, the licensee returned Unit 2 to power operation after a refueling/maintenance outage that lasted over two months. The inspectors monitored the performance of the operations department during the restart and made the following observations:

- New startup controlling procedures were used by the operators during the unit startup. These procedures appeared to provide for good control of startup evolutions. However, the procedure for unit startup, 2-GOP-1.1, Unit Startup, RCS Heatup From AMBIENT TO 195 F, revision 0, should have been clearer in recognizing the plant entry conditions for restart after correction of the valve leakage problem discussed in paragraph 3.f.

- Similar to previous startups, operator attention to detail and sensitivity to plant conditions and reactivity management continued to be very good. Good communications and self checking techniques were frequently observed between operations personnel and was considered to be a continuing strength.

On June 6, approximately 25 minutes after Unit 2 was connected to the grid, a loss of electrical load was experienced. The unit was supplying approximately 80 megawatts of power at the time. The loss of load occurred when a crew working in the switchyard noticed that one of the electrical disconnects in the electrical flowpath from Unit 2 to the grid was arcing and appeared to be on fire. The supervisor of the crew notified the load dispatcher of the condition. In accordance with normal policy, the dispatcher opened a breaker in the switchyard to remove the load from the arcing disconnect. After the load was disconnected, the arcing stopped. The operators on Unit 2 responded to the loss of load and were able to stabilize the unit and reduce reactor power from approximately 25 percent to less than 5 percent over the next hour. Based on the excellent performance by the operators, no reactor or turbine trip occurred. Several problems were encountered during the transient including improper operation of the A feed regulation bypass valve, and setpoint drifting of the A steam generator PORV. All problems were corrected over the next 18 hours and the unit was again connected to the grid early on June 8, 1991.

c. Biweekly Inspections

The inspectors conducted biweekly inspections in the following areas: verification review and walkdown of safety-related tagouts in effect; review of sampling program (e.g., primary and secondary coolant samples, boric acid tank samples, plant liquid and gaseous samples); observation of control room shift turnover; review of implementation of the plant problem identification system; verification of selected portions of containment isolation lineups; and verification that notices to workers are posted as required by 10 CFR 19.

On June 6, 1991, Unit 1, while operating at 100 percent power, turbine control problems occurred that resulted in an 80 MWE power increase. The operator noticed and logged the following and immediately took manual control of the turbine:

. All turbine governor valve went to 100% open
. Rods stepping out in auto
. Turbine load going to 880 MWE
. Reactor high power alarm at 103%
. High steam line flow on two out of three channels

The turbine control problem was caused by a failure of the main speed pickup card for the turbine governor control circuit. The licensee wrote station deviation S-91-0887 to document and evaluate the event. The inspector witnessed portions of the licensee's response to the transient and reviewed several of the control room recorder and alarm printouts. The inspector noted that the licensee was operating the turbine with the governor valve position limiter set at 100 percent turbine load which did not restrict governor valve movement. The turbine is oversized when compared to the 100 percent reactor power

limit and two of the governor valves are not full open at 100 percent reactor power. Therefore, when all of the governor valves came full open, reactor power exceeded the licensed limit for a brief period of time.

The inspectors reviewed the safety analysis chapter of the UFSAR (Chapter 14) to determine if there was any restriction on turbine load limits. Section 14.2.8, Excessive Load Increase Incident, stated that excessive loading by the operator or by system demand would be prevented by the turbine load limiter. The UFSAR further indicated that reactor protection is provided by the high reactor power and delta-T trip setpoints. The inspectors reviewed the turbine operating procedure 1-OP-2.2.1, dated January 2, 1990 and the turbine inlet valve stroke test procedure 1-PT-29.1, dated January 6, 1990, for information on use of the turbine load limiter. Both station procedures instructed the operator to set the limiter at 100 percent. With the turbine oversized with respect to full reactor power, setting the limiter for 100 percent valve open does not prevent exceeding the 100 percent licensed reactor power limits. Thus, the load limiter requirements from Section 14.2.8 of the UFSAR have not been incorporated into station procedures.

10 CFR 50, Appendix B, Criterion V, requires that activities affecting quality be prescribed by documented instructions or procedures of a type appropriate to the circumstances and shall be accomplished in accordance with instructions, or procedures. The failure to provide adequate instructions and/or procedures to implement the UFSAR operating requirements is identified as a second example of Violation, 50-280, 281/90-10-01, Inadequate Turbine Operating and Testing Procedures.

d. Other Inspection Activities

Inspections included areas in the Units 1 and 2 cable vaults, vital battery rooms, steam safeguards areas, emergency switchgear rooms, diesel generator rooms, control room, auxiliary building, cable penetration areas, Unit 2 containment, low level intake structure, and the safeguards valve pit and pump pit areas. RCS 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. The inspectors routinely independently calculated RCS leak rates using the NRC Independent Measurements Leak Rate Program (RCSLK9). On a regular basis, RWPs were reviewed, and specific work activities were monitored to assure they were being conducted per the RWPs. Selected radiation protection instruments were periodically checked, and equipment operability and calibration frequency were verified.

During a control room observation on May 13, 1991, the inspectors noted that the Unit 1 CRO and SRO became involved with a problem associated with the inside personnel airlock door. Specifically, a

team of electricians who were exiting containment, reported that the inside airlock door was jammed and would not close. This condition resulted in the electricians being stuck in the airlock and not being able to open the outside door because of containment integrity interlocks and differential pressure. The inspectors observed operations response to this condition and noted that there was some question as to what actions should be taken. The Operations Superintendent's response to the situation which included calming the team of electricians was considered good. Discussions with the control room operators, though, revealed that many operators had a personal experience associated with being stuck in the airlock.

The inspectors reviewed a printout of DRs associated with the airlock over the past 2 years and noted that there has been a continuing problem with this equipment. The airlock doors are required by TS 3.8 to be operable and closed for containment integrity. Additionally, the inspectors inspected the material condition of the Unit 2 inside airlock door which is identical to the Unit 1 door. A combination of original design (i.e. single point of attachment and closure mechanism) with the age and condition of the doors appears to have contributed to the door failures and jamming. Additionally, it was not clear that the electricians operating the door had the training or experience to ensure proper operations.

The inspectors discussed the above observations and findings with plant management. The station manager indicated that airlock door operation was a continuing problem for both units and that actions were planned. The licensee sated that upgrading of the doors had been evaluated and was at one time on the proposed plant improvements list. However, priority of this upgrade has decreased to make way for more pressing items. The station manager indicated that airlock improvements will be reviewed in light of recent problems and that short term actions, which may include using a trained door operator to operate the door, will be implemented. Previous corrective actions, associated with air lock deficiencies, have been ineffective in correcting the material condition of the equipment and is identified as a weakness. It should be noted, that establishing containment integrity for the heatup of Unit 2 from the current refueling outage had to be delayed, due in part to air lock door problems.

e. Physical Security Program Inspections

In the course of monthly activities, the inspectors included a review of the licensee's physical security program. The performance of various shifts of the security force was observed in the conduct of daily activities to include: protected and vital areas access controls; searching of personnel, packages and vehicles; badge issuance and retrieval; escorting of visitors; and patrols and compensatory posts. No discrepancies were noted.

f. Licensee 10 CFR 50.72 Reports

On June 3, 1991, the licensee made a report in accordance with 10 CFR 50.72 regarding entrance into the station emergency plan. At 1431 hours, Unit 2 declared a UE due to uncontrolled RCS leakage exceeding TS 3.1.C.5 limits of 10 GPM. The unit was in hot shutdown with RCS temperature and pressure in the normal operating range (i.e. 547 degrees F and 2235 psig) at the time of the event. The leakage rate was calculated to be approximately 16 GPM and was from the packing area of the "C" RCS RTD manifold isolation valve 2-RC-95 and was observed blowing into the containment. The leakage was unisolable from the RCS loop and the licensee commenced a plant cooldown/depressurization at approximately 1432 as required by the TS. The UE was terminated at 0506 on June 3, after the unit reached cold shutdown at 0454. The RCS leakage first appeared as a 6 GPM leak into the PDTT through the packing leakoff line and the licensee attempted to backseat the valve to stop the leakage. The packing blew out after several attempts to backseat the valve. Operations personnel, who had just climbed down from trying to backseat the valve, were not hurt when the packing failed. The resident inspector was on-site monitoring startup evolutions when the event occurred and observed the licensee actions and followup. The reporting requirements of 10 CFR 50.72 were met and the licensee actions associated with taking the plant to a cold shutdown condition were in accordance with the TS. The Operations Manager's decision to take the plant to cold shutdown was not delayed and action was started within the first ten minutes after determining that the leakage rate exceeded TS limits.

The valve repairs and failure determination is further discussed in paragraph 4.d.

g. Reduced Inventory Conditions - Unit 2

Unit 2 entered a reduced inventory condition on May 17, 1991 in order to conduct maintenance activities on safety injection check valves. This condition was exited on May 21, 1991. Prior to entry into this condition, the inspectors conducted a review of the licensee's responses and implemented actions with regards to the requirements of Generic Letter 88-17, Loss of Decay Heat Removal. No discrepancies were noted during the review. The specific items reviewed were:

- Generic Letter 88-17 - The inspectors reviewed the subject letter including the licensee's response to the letter dated January 6, with supplemental responses dated February 3, September 29, October 31, 1989, October 5, and November 16, 1990.

- Administrative Controls - The inspectors discussed controls and procedures in affect to control reduced inventory operation with the Operations Superintendent as well as several senior reactor operators and licensed operators. Additionally, the inspectors attended a reduced inventory planning meeting on May 14, 1991,

where controls, precautions and required equipment status were reviewed.

- Containment Closure Activity - The licensee's procedures require that the status of the containment configuration be established and verified prior to entering a reduced inventory condition. In addition, the procedure for loss of RHR capability directs containment closure action to be initiated and continued until the RHR system is returned to service and core conditions are verified normal. The inspectors verified that the licensee has prepared procedures to reasonably assure that containment closure will be achieved prior to the time at which core uncovery could occur. This was done by reviewing 2-OP-3.4, Draining the Reactor Coolant System, dated March 28, 1991, 2-OP-1G, Refueling Containment Integrity and RCS Mid-Loop Containment Closure Checklist, dated April 28, 1989, and 2-AP-27, Loss of Decay Heat Removal Capability, dated March 28, 1991. Other than the containment personnel entry hatch and the equipment hatch, no containment openings will exist. During a containment tour on May 15, 1991, the inspector verified that there was little obstruction in the way of the equipment hatch and that the containment closure crew should have little difficulty in closing the hatch.

- RCS Temperature - The inspectors verified that the controlling procedure for draining the RCS, 2-OP-3.4 required at least two operable incore temperature indicators prior to draining the RCS to a reduced inventory condition. The inspectors also verified that the control room operators record the temperatures every six hours in their log as required by periodic test 2-PT-36, Instrument Surveillance. In addition a supplemental check list, Control Room Operator Reduced RCS Inventory Relief Checklist, requires at least two operable core exit thermocouples (i.e. one from each train).

- RCS Level Indication - The licensee has installed one means of level indication which provides continuous readout in the control room. This system is calibrated and provides a low level alarm for both low level and loss of level. In a letter dated October 31, 1989, the licensee committed to install a second means of RCS level indication prior to the end of the current Unit 2 refueling outage. The licensee had completed the construction portion of this modification, and this instrumentation was available to operators during this reduced inventory period and provided additional assurance to operators of the RCS water level. The licensee plans to validate this equipment during this reduced inventory evolution and operators interviewed by the inspector were aware of the current status. During the May 14, 1991, planning meeting, the licensee indicated that during the initial drain-down to mid-loop an operator will be stationed inside the containment to visually

monitor the standpipe level. Additionally, operations was instructed to monitor the UT system and if differences between the two level monitoring systems were noted, the draining operation was to be stopped. The licensee's actions to make available this second means of level indication ahead of their commitment and prior to entry into reduced inventory condition demonstrated a positive sensitivity to safety and was identified as a strength.

- RCS Perturbations - The inspectors verified that the licensee has a procedure, OC-28, Assessment of Maintenance Activities for Potential Loss of Reactor Coolant Inventory dated January 22, 1991, that allows for operations' assessment of work on systems for potential loss of reactor coolant inventory during reduced RCS inventory conditions.

- RCS Inventory Addition - The inspectors verified that procedure 2-OP-3.4 required at least two available and operable means of adding inventory to the RCS. These are in addition to the RHR system. The procedure requires that in a reduced inventory condition, one charging/safety injection pump and one LHSI pump must be available with appropriate flowpaths to the core. However, during the review of the licensee's procedure 2-OP-3.4 the inspector noted that the procedure did not specify a preferred injection path to the RC hot leg as specified in the licensee's response to GL 88-17, dated January 6, 1989. In that response the licensee stated that, "The flow path checklist specifies that the hot leg injection flow path is preferred, with cold leg injection available as an alternative." The inspector discussed with the licensee a concern that the controlling procedure (2-OP-3.4) did not specify the preferred flow path. The licensee indicated that the checklist referenced in their response is 2-OC-6 which does specify the hot leg as the preferred path. This checklist is performed every 12 hours by the control room operators. However, use of the checklist to establish the preferred flow path in-lieu of the operating procedure may not ensure that the preferred flow path is available as a prerequisite for the intended inventory reduction. The inspector was satisfied that the preferred flow path will be aligned for the majority of the reduced inventory operations scheduled for May 17, 1991. The licensee is evaluating the need to reference the checklist or to specify the preferred flow path in the operating procedure as well as in the turnover checklist.

- Loop Stop Valves - The licensee utilizes RCS loop isolation valves for loop isolation. Nozzle dams are not used. The licensee uses an operational checklist (OC-28) to ensure that the reactor vessel upper plenum is adequately vented when maintenance activities require opening of a RCS cold leg pressure boundary. The licensee ensured that the reactor vessel

was adequately vented by maintaining A and B loops unisolated with the loop bypass valves open.

- Contingency Plans to Repower Vital Busses - The vital and emergency electrical distribution system receives offsite power from the A and C reserve station service transformers during normal plant operations. The RHR pumps and the CCW pumps, the latter providing cooling water to the RHR heat exchangers, operate off stub busses attached to the 2J and 2H emergency busses. The stub busses are shed during degraded or undervoltage situations, but can be reconnected to the emergency busses by closing a breaker. The equipment for the two additional means for adding inventory to the RCS, charging pumps and LHSI pumps are powered off the 2H and 2J emergency busses. During normal operations, the number 2 EDG supplies power to the 2H emergency bus in case of a degraded or undervoltage situation, and the number 3 EDG supplies power to the 2J bus. During this period, the licensee had the A and C reserve station service transformers powering the emergency busses, and 2 and 3 EDGs available as emergency power sources. The inspector noted during a review of planned testing that the licensee had scheduled performance of the number 2 EDG surveillance test while in reduced inventory. This test which is a 6-hour test, aligns the EDG to the electrical grid for loading and grid perturbations could affect the EDG availability. These conditions have occurred in the past and are recognized in industry and regulatory information. The licensee subsequently informed the inspector that they reevaluated testing of the EDG during reduced inventory operation and elected to either test the EDG prior to or after reduced inventory operations as long as their required surveillance grace period was not exceeded.

During the above review the inspector noted that a number of procedures were required to perform reduced inventory operations. This is similar to other procedure problems that have been noted at Surry and the licensee indicated that consolidating the reduced inventory evolution will be considered during the procedure upgrade program.

Within the areas inspected, no violations were identified.

4. Maintenance Inspections (62703 & 42700)

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

The following maintenance activities were reviewed:

a. Non-Regenerative Heat Exchanger 2-CH-E-2

The inspectors reviewed the licensee's repair efforts on plugging two tubes and repairing one leaking plug. The work was performed using WO. 3800097306. Corrective maintenance procedure MMP-C-CG-119, Disassembly, Leak Detection, Repair, Reassembly of Non-Regenerative Letdown Heat Exchanger-Safety Related, dated October 30, 1989, was used for the repair. The licensee used a mechanical plug rather than the welded plug for the repair. The use of the mechanical plug decreased the radiation exposure. A problem was encountered when the warehouse stock flexitalic gasket did not have the same dimensions as those on the tubesheet. Part of the old gasket had to be reused. The inspectors will followup on this problem during the next inspection period.

b. Modification of 2-SW-MOV-205D

The inspectors monitored the licensee's activities associated with the modification of 2-SW-MOV-205D HBC adapter and valve. The maintenance was accomplished in accordance with WO 380011483. The WO had an engineering transmittal attached that provided instructions and specifications for performing this modification. The inspectors periodically visited the job site, and while at the job site reviewed the WO, the post-maintenance test follower, and the engineering transmittal.

The purpose of this minor modification was to replace the screws that secured the HBC adapter to the valve body with larger diameter cap screws. This was required because movement between the HBC adapter and valve body was noted during operation of the valve. More torque could be applied to the larger cap screws to ensure that the HBC adapter would remain secure to the valve body. The modification required removal of the Limitorque operator and HBC adapter, drilling and tapping the valve body, enlarging the HBC adapter bolt holes, reinstallation of the Limitorque operator and HBC adapter to the valve body, and setting of the Limitorque operator switches and stops. This same modification was performed on the 2-SW-MOV-205A, B, and C valves and also on the 2-SW-MOV-204 A, B, C, and D valves.

The licensee considered the modification to be an equipment enhancement and that the MOVs were operable in the as-found condition. This was based on the MOVs satisfactorily passing their surveillance tests, and that the previous condition, before the modification, did not affect the valves ability to reposition to the open accident position. Unit 1 and 2 SW-MOV-204, and 205 valves and operators are scheduled for replacement during the next refueling outages.

While monitoring the modification, the inspectors noted that the contractors performing the work were not provided a SNSOC approved procedure to accomplish the work, and that the WO was annotated that a procedure was not required. The inspectors reviewed VPAP-801, Maintenance Program, Revision 1, Maintenance Program. VPAP-801 provides guidelines that specify when procedures are required.

Although a SNSOC approved procedure was not available the craft were working per the instructions of an engineering transmittal. The inspectors questioned the purpose of the engineering transmittal. The inspectors were informed that the engineering transmittal provided written guidance from maintenance engineering to craft personnel for performing the modification, and that normally engineering transmittals are not utilized as procedures. The inspectors discussed the use of engineering transmittals as procedures with the Maintenance Superintendent. The Maintenance Superintendent considered engineering transmittals to be documented instructions and therefore an acceptable procedure. The inspectors did not consider engineering transmittals as documented instructions because station administrative procedures did not address the use of engineering transmittals as an alternative to a SNSOC approved procedure.

With minor modification in process for 2-SW-MOV-205D, the inspectors questioned why the craft was not utilizing an EWR to perform the the work, and why an EWR was not approved prior to the performance of the modification. The inspectors were informed that in order to expedite maintenance, an EWR is prepared in parallel with or after the maintenance is completed. The system that contains the modified components is not declared operable until SNSOC approves the EWR that documents the modification.

The inspectors concluded that station administrative instructions SUADM-ENG-01, Engineering Work Request, Revision 1, and SUADM-ENG-13, DCP/EWR Implementation and Closeout, Revision 0, did not clearly address the process of issuing an EWR in parallel with or after completion of the work and that SNSOC approval of the EWR was required prior to declaring the system operable. This was discussed with the Superintendent of Engineering who stated that administrative procedures that govern modifications are currently being revised, and that these issues would be clarified by the revisions. The inspectors reviewed EWR 90-272, revision K, MOV Modifications Surry 1/2, and verified that SNSOC approval was obtained prior to the time the recirculation spray system was required to be operable.

c. Repairs to Check Valve 2-SI-85

The inspectors reviewed the work package for the open/inspect/repair of check valve 2-SI-85. This maintenance was performed in accordance with WO 3800088856 and procedure 2-MPT-0417-04, Inspection of SI Check Valves 2-SI-79, 2-SI-82, and 2-SI-85, dated March 5, 1991. Inspection of the valve internals revealed that valve seat and disc were worn. The valve disc was replaced and the valve was reassembled. Replacement of the valve seat would have required installation of a new check valve which was a significant increase in the job scope and therefore not performed. Other difficulties encountered during the maintenance was high radiation dose rates and water in the maintenance area. Water in the maintenance area

prevented the mechanics from obtaining a satisfactory blue check. The inspectors also reviewed the post-maintenance test requirements. No discrepancies were noted. On May 28, check valve 2-SI-85 was satisfactorily seat leak checked. The testing is discussed in paragraph 5.b.

d. Repairs to Valve 2-RC-95

As discussed in section 3.f of this report, attempts were made to back seat 2-RC-95 to stop a valve packing leak. Subsequently, the packing blew out resulting in entry into the emergency plan and the declaration of a UE. The unit had to be taken to cold shutdown to depressurize the leak for repairs. Even after reducing the pressure to 15 psig the leakage was still approximately 15 gpm. The licensee was considering the use of a freeze seal to isolate the valve for repairs. The other alternative was to go into reduced inventory since the valve was not isolable from the RCS loop. In order for the successful application of a freeze seal the licensee's procedure required the flow rate in the area to be decreased to less than 5 gpm. To accomplish this, the valve stem was turned in the shut position to reduced leakage and system pressure was reduced to 15 psig. After safety evaluation 91-146 was reviewed and approved by the SNSOC, the freeze seal was accomplished by procedure MMP-C-FS-260, dated April 24, 1991. The inspectors reviewed the freeze seal procedure and the safety evaluation. Comments on the freeze seal procedure in the area of operations involvement with the authorization to melt the seal and comments associated with the licensee's oversight of the freeze seal contractor were given to plant management.

The freeze seal was installed and no leakage was noted when valve 2-RC-95 was disassembled. Inspection of valve 2-RC-95 revealed that the valve stem had separated from the disc. The licensee determined that the valve is no longer needed for plant operations and a plant modification was made that removed the internals from the valve and blanked the bonnet. The licensee determined that the valve stem and disc were separated (unscrewed) when initial back seating operations were performed to stop the valve packing leak. The valve yoke bushing prevented the stem from being ejected from the valve. The licensee plans to have a failure analysis performed on the valve disc and stem.

The Operations Department issued a shift order to establish the following guidelines associated with valve operation: The guidelines were:

- Do not use a valve wrench on any safety related valve.
- If RCS leakage is identified, do not backseat the valve without concurrence from both the Operation Manager on call and engineering.

Review of the failure analysis will be performed after the results are received by the licensee.

Within the areas inspected, no violations were identified.

5. Surveillance Inspections (61726 & 42700)

During the reporting period, the inspectors reviewed various surveillance activities to assure compliance with the appropriate procedures as follows:

- Test prerequisites were met.
- Tests were performed in accordance with approved procedures.
- Test procedures appeared to perform their intended function.
- Adequate coordination existed among personnel involved in the test.
- Test data was properly collected and recorded.

The following surveillances were either reviewed or observed:

a. LHSI and Outside RS Testing

During surveillance testing on the Unit 2 LHSI pumps, 2-SI-P-1A and 2-SI-P-1B, and Unit 1 outside RS pump 1-RS-P-2A, the inspectors noted, during review of the operator logs, that seal head tank low level annunciators actuated. The inspectors monitored the licensee's corrective actions in response to the seal head tank low level alarms.

The inspectors reviewed the seal designs and noted that each of the LHSI and outside RS pumps contain an inboard and outboard seal. The purpose of the seals are to provide a pressure boundary so radioactive fluid is not released into the safeguards building when the pumps take a suction from the containment sump during accident conditions. The inboard seal cooling water is supplied from the discharge of the pump and the outboard seal is cooled by the action of a pumping ring and cooler unit. The cooler unit (one for each pump) is a closed loop filled with water. The cooler unit contains a seal head tank with high and low level switches and a cooling coil. During pump operation, the pumping ring circulates water from the area between the inboard and outboard seals through the cooling coil and back to the area between the seals. The seal head tank level switch annunciator alarms in the control room.

Maintenance performed on the LHSI pumps' seal cooler units during the refueling outage required that the systems be drained. On April 20,

maintenance on the Unit 2 A LHSI pump seal cooler unit was completed. The seal cooler unit was filled with water and the pump was satisfactorily tested in accordance with 2-PT-18.1, LHSI Test and Flushing of Sensitized Stainless Steel Piping, dated October 25, 1991. On May 8, the Unit 2 A LHSI pump was again tested in accordance with 2-PT-18.1. When the pump was initially started, the seal head tank annunciator alarmed and the pump was secured. The seal head tank was filled in accordance with the procedure and operators restarted the pump. The seal head tank annunciator again alarmed and pump was secured. WO 3800111182 was initiated to troubleshoot the seal head tank low level switch. The switch was inspected but no problems were identified. On the following day, the seal head tank was refilled. The Unit 2 A LHSI pump was started and operated without the seal head tank low level annuciator alarming. On May 21, the Unit 2 A LHSI pump was operated several times to support reactor fill evolutions. On one occasion the seal head tank low level annuciator alarmed for several seconds and cleared. On May 22, during the first two start attempts of A LHSI pump, the seal head tank low level annunciator alarmed and the pump was secured. The seal head tank was refilled in accordance with procedure and the pump was restarted and operated without the seal head tank level annunciator alarming. The inspector noted that no DRs were initiated for the above annunciated conditions.

On May 23, the Unit 2 B LHSI pump was started and secured because its seal head tank annunciator alarmed. In this case, however, a DR (S-91-0779) was initiated. Troubleshooting identified that air was present in the pump's seal cooling system. When the the LHSI pumps were started the air in the cooling system would compress and level in the seal head tank would decrease. The system was designed to be operated full of water. The air was introduced when the system was opened for maintenance during the refueling outage. The system's configuration is such that it is extremely difficult to vent the air out while filling the system. The Unit 2 LHSI pumps seal cooling systems were vented and the pumps operated without the low level seal head tank annunciator alarming. The licensee considers that most if not all of the air is out of the system and that the Unit 2 LHSI pumps were operational.

On June 4, during the performance of Unit 1 surveillance test 1-PT-17.3, Containment Outside Recirculation Spray Pump, dated February 1990, the seal head tank low level annunciator alarmed when the containment outside RS pump 1-RS-P-2A was started. The pump was secured and the seal head tank filled in accordance with procedure. The pump was restarted and operated without the seal head tank low level annunciator alarming. The pump was considered fully operable. A DR was not initiated for this abnormal condition. The inspectors questioned why a DR was not initiated and if there was air in the seal cooling system.

As a result of the inspectors concern with regard to seal head tank operation, discussions were held on June 6 with the licensee. The inspectors were informed that the seal cooling systems for the Unit 2 LHSI and Unit 1 containment outside RS pumps were similar in configuration and that air in the system was the probable cause of the June 4 seal head tank low level alarm that occurred on pump 1-RS-P-2A. The inspectors were also informed that in February and August of 1990 the seal head tank low level alarm annunciated on the same pump. In August 1990, DR S1-90-1104 was initiated as a result of the seal head tank low level annunciator alarming after the pump was started. The inspectors reviewed the corrective action assigned to the DR. The corrective action involved refilling the seal tank when the alarm occurred and did not require any actions to investigate the cause of the alarm. A DR was not initiated for the February 1990 alarm.

The licensee stated that pump 1-RS-P-2A was considered operable with air in the seal cooling system because there was an adequate volume of water in the seal cooling system to provide cooling to the pump outboard seals. The inspectors questioned what operators would do during an accident when the outside containment RS pumps were started and the seal head tank low level annuciator alarmed. The inspectors were informed that there was no specific guidance in this area and the shift supervisor would have to make a judgement call on securing the pump or continuing to operate it in the alarm condition. The inspectors consider that annunciation of the seal head tank low level alarms during an accident would add unnecessary work and confusion for the operators during a critical time.

The inspectors consider that the seal head tank low level annunciator alarms on the Unit 2 LHSI pumps and the Unit 1 containment outside recirculation pump 1-RS-P-2A were conditions adverse to quality that were not promptly identified nor was adequate corrective action initiated. During the Unit 2 refueling outage the A LHSI seal head tank annuciator alarmed numerous times. DRs were not initiated to document these conditions. Also, seal head tank low level alarms have occurred on pump 1-RS-P-2A and DRs were not always initiated to document these conditions. When a DR was issued to document a low level alarm on pump 1-RS-P-2A, the corrective action was inadequate to prevent reoccurrence.

Failure to promptly identify or correct the conditions adverse to quality associated with the seal head tank low level alarms is identified as a violation of 10 CFR 50, Appendix B, Criterion XVI 50-280, 281/91-14-02, Failure to Identify and Correct Conditions Adverse to Quality.

b. Event V Pressure Isolation Valve Seat Leak Testing

TS 3.1.c.7a and TS Table 4.1-2A, item 18 specifies test frequency and seat leak rate limits for Event V pressure isolation valves SI-79,

SI-241, SI-82, SI-242, SI-85, and SI-243. On May 28, the inspectors monitored portions of the seat leak testing accomplished on Unit 2 check valves 2-SI-79, 2-SI-82, and 2-SI-85. The inspectors also reviewed the completed copy of 2-PT-18.11, SI Cold Leg Check Valve Leakage-Primary Coolant System Pressure Isolation Valves, dated June 5, 1990. Results of this review indicated that individual leak rates in lieu of combined leakage rates were obtained, leakage rates obtained at lower than normal operating pressure were normalized, and all procedure calculations were correct. No discrepancies were noted.

c. Control Rod Drop Testing

On June 5, 1991, the inspectors witnessed portions of 2-PT-7.1, Cold Rod Drops, dated May 28, 1991. The purpose of this test was to ensure rod freedom after the cooldown of Unit 2 for repairs to valve 2-RC-95. The licensee elected to perform this test during hot shutdown conditions and a PAR was issued on May 30, 1991, to allow this. Additionally, the safety evaluation to allow continued operations during cycle 10 with rod M-12 stuck was modified to recognize that rod freedom testing could be performed either hot or cold but prior to criticality. Equipment performed as expected and no discrepancies were noted.

Within the areas inspected, one violation was identified.

6. Licensee Event Report Review (92700)

The inspector reviewed the LER's listed below to ascertain whether NRC reporting requirements were being met and to evaluate initial adequacy of the corrective actions. The inspector's review also included followup on implementation of corrective action and review of licensee documentation that all required corrective actions were complete.

(Closed) LER 280/91-04, Two of Three Emergency Diesel Generators Inoperable. The issue involved a tagout of one of the two redundant fuel oil transfer pumps for an EDG which was required to be fully operable based on plant conditions at the time. This event was addressed in Inspection Report 280,281/91-10 and an NCV was identified in that report. The inspector reviewed licensee actions at that time and also reviewed additional corrective actions addressed in this report. Licensee corrective actions appear to be adequate.

(Closed) LER 280/91-06, Unit 1 Auxiliary Feedwater System Cross-Connect Capability From Unit 2 Inoperable In Excess of Technical Specifications Allowed Time Due to a Drawing Error. The issue involved an incorrect configuration condition for underground suction line for a safety-related AFW pump. This event was addressed in Inspection Report 280,281/91-10 and an NCV was identified in that report. The inspectors reviewed the licensee actions at the time of the event and also reviewed the corrective

actions addressed in this report. Licensee corrective actions appear to be adequate.

Within the areas inspected, no violations were identified.

7. Evaluation of Licensee Self-Assessment Capability (40500)

During this inspection period, the NRR project manager for Surry conducted a review of the licensee's program for the screening of plant changes, and proposed tests and experiments to determine if a safety evaluation is required and the process for preparing, reviewing, and approving safety evaluations. This review focused on the testing of main steam safety valves accomplished during the past 12 months.

In October, 1990, testing of the Unit 1 main steam safety valves lift setpoints was performed using the Furmanite Trevitest method. Similar testing of the Unit 2 main steam safety valves at approximately 70 percent of rated power was conducted in March, 1991. The licensee has previously performed a 10 CFR 50.59 safety evaluation dated October 2, 1990, which concluded that testing of the above cited safety valves at power did not present an unreviewed safety question. A review of the safety evaluation showed that it was prepared using the then current Surry Power Station Procedure SUADM-LR-12 which has subsequently been superseded by Station Administrative Procedure No. VPAP-3001 dated April 1, 1991. The safety evaluation referenced the steamline break analysis in Section 14.3.2 of the Station UFSAR. Section 14.3.2 of the UFSAR indicated that if a safety valve were to inadvertently stick open, the most severe transient would occur at zero load without unacceptable consequences. The analysis assumed, among other things, a steam release rate of 247 pounds per hour which is equal to or greater than the relief capacity of any single dump or main steam safety valve and the results indicated compliance with the design basis as defined in the UFSAR. The inspection concluded that the analysis was procedurally correct and supported the licensee's findings that testing of the main steam line safety valves at power would not constitute an unreviewed safety question. Also, the inspector concluded that the licensee's analysis methodology is in compliance with the licensing basis as described in the UFSAR.

Within the areas inspected, no violations were identified.

8. Exit Interview

The inspection scope and results were summarized on June 11, 1991 with those individuals identified by an asterisk in paragraph 1. The following summary of inspection activity was discussed by the inspectors during this exit.

Item Number	Description and Reference
VIO 50-280,281/91-14-01	Failure to provide adequate procedures and/or instructions with two examples.

a. Inadequate implementation of a waste gas decay tank TS. (paragraph 3.a)

b. Inadequate turbine operating and testing procedures. (paragraph 3.c)

VIO 50-280,281/91-14-02 Failure to identify and correct conditions adverse to quality. (paragraph 5.a)

Licensee management was informed of the strengths and weaknesses identified in paragraph 3 and of the items closed in paragraph 6.

The licensee acknowledged the inspection conclusions with no dissenting comments. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

9. Index of Acronyms and Initialisms

AFW	-	AUXILIARY FEEDWATER
CCW	-	COMPONENT COOLING WATER
CFR	-	CODE OF FEDERAL REGULATIONS
CRO	-	CONTROL ROOM OPERATOR
DR	-	DEVIATION REPORT
EDG	-	EMERGENCY DIESEL GENERATOR
ESF	-	ENGINEERED SAFETY FEATURE
EWR	-	ENGINEERING WORK REQUEST
F	-	FAHRENHEIT
GL	-	GENERIC LETTER
GPM	-	GALLONS PER MINUTE
LER	-	LICENSEE EVENT REPORT
LCO	-	LIMITING CONDITIONS OF OPERATION
LHSI	-	LOW HEAD SAFETY INJECTION
MOV	-	MOTOR OPERATED VALVE
MWE	-	MEGAWATT ELECTRICAL
NCV	-	NON-CITED VIOLATION
NOUE	-	NOTICE OF UNUSUAL EVENT
NRC	-	NUCLEAR REGULATORY COMMISSION
NRR	-	NUCLEAR REACTOR REGULATION
PAR	-	PROCEDURE ACTION REQUEST
PDTT	-	PRIMARY DRAIN TRANSFER TANK
PSIG	-	POUNDS PER SQUARE INCH
PORV	-	POWER OPERATED RELIEF VALVE
RC	-	REACTOR COOLANT
RCS	-	REACTOR COOLANT SYSTEM
RHR	-	RESIDUAL HEAT REMOVAL
RS	-	RECIRCULATION SPRAY

RTD	-	RESISTANCE TEMPERATURE DETECTOR
RWP	-	RADIATION WORK PERMIT
SRO	-	SENIOR REACTOR OPERATOR
SI	-	SAFETY INJECTION
SNSOC	-	STATION NUCLEAR AND SAFETY OPERATING COMMITTEE
SW	-	SERVICE WATER
TS	-	TECHNICAL SPECIFICATIONS
UFSAR	-	UPDATED FINAL SAFETY ANALYSIS REPORT
UE	-	UNUSUAL EVENT
UT	-	ULTRASONIC TEST
VPAP	-	VIRGINIA POWER ADMINISTRATIVE PROCEDURES
WGDT	-	WASTE GAS DECAY TANK
WO	-	WORK ORDER