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

Report Nos.: 50-280/86-02 and 50-281/86-02

Licensee: Virginia Electric and Power Company
Richmond, VA 23261

Docket Nos.: 50-280 and 50-281 License Nos.: DPR-32 and DPR-37

Facility Name: Surry 1 and 2

Inspection Conducted: January 7 - February 3, 1986

Inspectors: D. J. Burke — 3/4/86
D. J. Burke, Senior Resident Inspector — Date Signed

for D. J. Burke — 3/4/86
M. J. Davis, Resident Inspector — Date Signed

Approved by: A. J. Ignatonis — 3/4/86
A. J. Ignatonis, Acting Section Chief — Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, unannounced inspection entailed 210 inspector-hours in the areas of plant operations and operating records, plant maintenance and surveillance, plant security, followup of events, IE Bulletins, and open items identified in the VPB Inspection Report (50-280 & 50-281/85-35).

Results: One violation was identified - Inadequate procedures and actions to assure that vendor identified conditions adverse to quality are promptly identified and corrected - paragraph 6.a.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

R. F. Saunders, Station Manager
D. L. Benson, Assistant Station Manager
H. L. Miller, Assistant Station Manager
D. A. Christian, Superintendent of Operations
E. S. Grecheck, Superintendent of Technical Services
J. W. Patrick, Superintendent of Maintenance
J. Logan, Supervisor, Safety Engineering Staff
S. Sarver, Superintendent of Health Physics
R. Johnson, Operations Supervisor
R. Driscoll, Site Quality Assurance Manager

Other licensee employees contacted included control room operators, shift technical advisors, shift supervisors, chemistry, health physics, plant maintenance, security, engineering, administrative, records, contractor personnel and supervisors.

2. Exit Interview

The inspection scope and findings were summarized on a weekly basis with certain individuals paragraph 1. A violation described in paragraph 6, inadequate procedures to assure proper identification and correction of vendor identified conditions, was discussed in detail. The licensee acknowledged the inspection finding and took no exception. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

3. Licensee Action on Previous Enforcement Matters

This subject was not inspected during this reporting period.

4. Operations

a. Units 1 and 2 were inspected and reviewed during the inspection period. The inspectors routinely toured the control room and other plant areas to verify that plant operations, testing and maintenance were being conducted in accordance with the facility Technical Specifications (TS) and procedures. The inspectors verified that monitoring equipment was recording as required, that equipment was properly tagged, and that plant housekeeping efforts were adequate. The inspectors also determined that appropriate radiation controls were properly established, that clean areas were being controlled in accordance with procedures, that excess material or equipment was stored properly, and that combustible material and debris were disposed of expeditiously.

During tours, the inspectors monitored the plant for unusual fluid leaks, piping vibrations, piping hanger and seismic restraint settings, various valve and breaker positions, equipment caution and danger tags, component positions, adequacy of fire fighting equipment and instrument calibration dates.

Certain tours were conducted on backshifts. Inspections included areas in the Units 1 and 2 cable vaults, vital battery rooms, fire pump house, Unit 1 containment, emergency switchgear rooms, diesel generator rooms, control room, auxiliary building, and cable penetration areas to verify certain breaker and equipment conditions and positions for safety-related components. The inspectors routinely conducted partial walkdowns of emergency core cooling systems and engineered safety features systems to verify operability and observe maintenance and testing of certain equipment and components in these systems.

b. Unit 1 started the reporting period at power. At 9:07 p.m., on January 7, 1986, Unit 1 tripped from 97% power due to a low water level condition in the "A" steam generator in coincidence with a steam flow/feed flow mismatch. The air operated main feedwater regulating valves were drifting closed due to decreasing Instrument Air (IA) system pressure and flow. The closing valves reduced main feedwater flow and steam generator level, which initiated the Reactor Protection System trip as designed. Safety systems functioned as required following the Unit 1 trip. The loss of the Unit 1, 1A header pressure was due to the freezing of moisture within the piping lines of the 1A dryer. 1A header pressure at the dryer outlet decreased to some 30 psig at the time of the trip, while the dryer inlet pressure remained at a nominal 100 psig. The licensee determined that the evaporative compressor which had been replaced in the Unit 1, 1A dryer on January 6 was operating around 28 degrees F; the low temperature led to the freezing of the precipitated moisture in the dryer. The compressor hot gas bypass valve was apparently not properly adjusted following compressor replacement. The bypass valve was adjusted to return the temperatures to their normal operating range (approx. 35 degrees F). In addition, a redundant source of 1A from the condensate polishing building air compressors was valved into the Units 1 and 2 1A dryer outlet headers. Following the Unit 1 trip, the Reactor Coolant System (RCS) Iodine-131 (dose equivalent) activity increased to approximately 1.83 µci/ml due to known fuel defects. The inspectors also verified proper operation of the reactor trip breakers and other equipment following the trip. Unit 1 was returned to power operation on January 8, 1986.

c. On January 19, 1986, Unit 1 suffered a turbine runback to approximately 70 percent of power due to four dropped peripheral rods in control bank A, Group 2 (Rods K-2, B-6, F-14, and P-10 which comprise one half the rods in Control Bank A). The rod drops occurred when an approved jumper wire with alligator clips apparently slipped off a terminal connection while being installed in the Rod Control System cabinet by an instrument technician; the jumper lead struck several other

connections, causing electrical arcing and failure of the 100 vdc power supply (PS-6) in the cabinet. The jumper was being installed due to previous failure of the redundant 100 vdc power supply to approximately 66 vdc (PS-3) to unblock an annunciated alarm. With both power supplies "failed", the Unit 1 control rods could not be stepped in or out, so the reactor was borated and manually tripped from some 60 percent power. The Iodine-131 (dose equivalent) activity in the RCS increased to 1.80 µci/ml due to known fuel leakage. Both 117 VAC to 100 vdc power supplies were replaced, and the rod control system satisfactorily tested. Unit 1 was restarted on January 19, 1985 (critical at 10:52 p.m.). The SRI observed portions of the above repairs, reviews, and restart operations. Licensee engineering verified that core thermal, radial flux, and delta flux parameters were not exceeded, although some 12 axial flux penalty minutes were accumulated for being outside the AFD target band.

One weakness in the Abnormal Procedures for dropped or misaligned control rod(s) was identified by the inspectors and the licensee; A.P.-1.4, Section 5.4 directed the operators to proceed to Hot Shutdown in accordance with Operating Procedure 3.1, when two or more control rods have been dropped. Operating Procedure 3.1 is the normal shutdown procedure and ramps the unit down at 150 MWE per hour. The Unit 1 and 2 Abnormal Procedures (A.P.-1.4) were revised on January 28, 1986, to state: If two or more rod cluster control assemblies (RCCAs) have been dropped, trip the reactor and go to EP-1.00, Reactor Trip/SI. Safety systems functioned normally after the reactor was manually tripped, except that the Reactor Operator manually initiated charging pump (HHSI) suction swapover or realignment from the volume control tank (VCT) to the refueling water storage tank (RWST), when the auto swapover on low VCT level (3 percent) did not appear to auto initiate. The auto initiating circuitry and valve realignment were tested and verified to be operating properly. The manual actuation was apparently initiated prematurely (not quite down to 3 percent) or in coincidence with the automatic swapover; also, the valves do require several seconds to realign suction from the VCT to the RWST. The inspectors had no further questions at this time.

d. At 4:36 a.m., on January 24, 1986, Unit 1 began ramping down due to concerns regarding the electrical arcing and melting of certain bolted cable leads on the isolated phase bus ductwork behind the Unit 1 'C' main transformer. The ductwork surrounds and provides ventilation cooling for the 22KV busses (and ductwork) from the main generator to the main output transformer. Eddy current heating of the cables, which electrically connect the pipe-like ductwork pieces together, occurs when resistance develops in the cables or their connections to the ductwork and ground. The power decrease was stopped at 7:45 a.m., at 42 percent while the cables and ductwork were inspected, and Unit 1 was manually tripped at 9:26 a.m., for a maintenance and snubber inspection outage.

e. Unit 2 operated at power for the duration of the reporting period; no reactor trips or shutdowns occurred. However, the circumstances and events occurring on January 19, 1986, which led to initiation of a Unit 2 rampdown to some 95 percent power were reviewed by the inspectors. At 5:27 p.m., on January 18, 1986, the Unit 2 reactor operator (RO) noted an increased Reactor Coolant System (RCS) leak rate when observing the volume control tank (VCT) level indication on the strip chart. An RCS leak rate determination was performed, and a leak rate of 6.7 gpm (total) and 0.6 gpm (unidentified) was calculated; TS 3.1.C limits are 10 and 1 gpm, respectively. Since the 'C' reactor coolant pump (RCP) no. 2 seal leakoff standpipe water level was also high (in alarm) and the VCT level trace decreased to some 3.7 gpm total and 0.4 gpm unidentified RCS leakage within two hours, licensee management concluded that the 'C' RCP seals were degrading, and that the controlled leakage from the seals was the reason for the increased leakage. Several hours later, the RCS leakage increased to 14.35 gpm total and 0.72 gpm unidentified, and at 3:37 a.m., on January 19, 1986, the RCS leakage was calculated to be some 16.82 gpm total and 2.48 gpm unidentified. A licensee inspection team was dispatched into the Unit 2 containment, and an orderly shutdown was commenced at 3:46 a.m., to prepare for seal work on the 'C' RCP. The inspection team found that a liquid drains diaphragm valve (DG-14) to the primary drains transfer tank (PDTT) inside containment was leaking, and observed stem packing leakage from the loop 'C' hot leg isolation valve MOV-2594. When the loop stop valve (MOV-2594) was manually backseated at 4:00 a.m., the RCS leak rate returned to normal (1.91 gpm total, 0.14 gpm unidentified), and the rampdown was subsequently stopped at some 95 percent power. The unit was later returned to full power operation. Since the licensee initiated shutdown of the unit with intentions of repairing the 'C' RCP seals, the licensee determined that a one-hour notification (10 CFR 50.72(b)(i)(a)) to the NRC was not required. RCS leakage from controlled sources, such as the RCP seals, is specifically excluded from the RCS leakage limits in Technical Specification 3.1.C.2 (unidentified) and 3.1.C.5 (total leakage). Due to the fluctuations in the RCS leakage rates and the RCP seal alarms, the licensee believed that the increased leakage was through the 'C' RCP seals; the actual increased leakage from the valve packing was identified and corrected in less than an hour. The licensee subsequently made a Part 50.72 notification to the NRC for information purposes, and will submit an LER on the event.

f. During routine plant system walkdowns, the inspectors observed the following items:

(1) On January 16, 1986, the Unit 2 Instrument Air Dryer (2-1A-D-1) flow was near zero; the condensate polishing (CP) building air compressors were supplying Unit 2 air. The Shift Supervisor had the CP air supply reduced, and 1A flow through the dryer increased to some 200 cfm (normal).

(2) An upper pin on the driveshaft for Motor Operated Valve MOV-CS-101A was displaced. The MOV was stroke tested and performed satisfactorily; the pin was repaired.

(3) The licensee reinsulated valve 2CS25 to ensure adequate cold weather protection, and is verifying proper local valve indication and identification on several valves that the inspectors identified (e.g., RS-155A, B, 156 A, B, SI-1862, A, B) as marginal due to painting over or displacement of the local "open" and "closed" indicators or tags. The declutching lever on MOV-RH-100 (for refueling operations) was also observed loose and displaced, and is being inspected and adjusted by the licensee.

5. Maintenance and Surveillance Items

a. The inspectors reviewed certain safety-related maintenance activities to ensure that the work and subsequent testing were performed in accordance with the Technical Specifications and approved plant procedures.

(1) The inspector reviewed portions of the licensee's program and activities concerning the inspection of bolting material (threaded fasteners) in safety-related valves. On January 7, 1986, the licensee observed that two of the sixteen 1 7/8-inch diameter by 14 1/2-inch long threaded studs on Unit 1 LHSI pump discharge motor operated valve (MOV-1890B) had failed. During replacement of all sixteen body to bonnet studs and nuts, one additional stud failed during removal. Licensee examination of the studs identified the material as J410SS (JB6 stamp), and the failure cause as intergranular stainless steel stress corrosion cracking (IGSSSC). A comprehensive stud inspection and repair program was initiated on Units 1 and 2 safety-related valves. The studs or bolts on some 170 valves in Unit 1 were inspected during the two week outage. Nine studs from smaller valves were also examined. All studs were replaced in every valve where one or more studs were identified as J410, JB6, or of questionable material (60 valves). The replacement material was carbon steel (B7). Some 59 valves were inspected in Unit 2 and no J410 or JB6 studs were found. The safety-related valves inside Unit 2 containment will be inspected during the February 21 - March 1, 1986 outage. An engineering analysis and safety evaluation by the licensee determined that the total failure of all the studs on any valve was not feasible due to the number of variables required for each IGSSSC cracking failure. This determination is supported by the stud inspection and test program findings. NRC review of the program continues.

While in the Unit 1 safeguards valve pit and containment, the inspectors observed portions of the valve stud replacement program and verified stud replacement on several valves (MOV-1890A, B, C, 1860A, 155A, 1864A, B, 1865A, etc.).

(2) The inspectors reviewed completed records and procedures for the replacement of two cold leg High Head Safety Injection (HHSI) system flow transmitters (FI-1961 and -1963) in the Unit 1 containment. The inspector questioned the QC inspector's signoff of the EQ transmitter and connector three days after the installation of the components on January 27, 1986. The licensee stated that the Conax electrical seal assembly had been installed backwards on both transmitters on January 27, 1986, at which time the error was identified. Assembly removal and repairs were completed on January 30, 1986, and subsequently QC verified. The licensee stated that the training and procedures (with attachments) for the installation of the EQ transmitters and seal assemblies will be reviewed and strengthened (IFI 280/86-02-01).

b. Several safety-related pump and motor operated valve performance tests were observed during the inspection period. Completed surveillance tests were also reviewed to ensure compliance with the Technical Specifications (TS). For example, review of the weekly electrical penetration leakage tests (PT-34), identified certain leaking containment Type B electrical penetrations on Unit 1 (2E, 11E, 18B) and 2(4D); however, the actual leakage as determined by the Type B and C testing (PT 16.2.A) was well within the limits of TS 4.4 and Appendix J to 10 CFR 50. The majority of the minor leakage appears to occur in the fittings, connections, and pressure gauges attached to the penetrations for testing rather than the penetration itself. Reactor coolant system leak rate determinations were also routinely reviewed during the inspection period.

6. Resolution and Followup Actions for the NRC Vendor Program Branch Inspection (Report 50-280,281/85-35, dated January 14, 1986)

The NRC Division of Quality Assurance Vendor Program Branch (VPB) inspectors conducted inspections at the Surry Power Station; the inspection results are documented in the report referenced above. The resident inspectors coordinated with the VPB inspectors during the VPB inspection at Surry. The following items were resolved by the resident inspectors:

a. Licensee processing and review of 10 CFR Part 21 reports (paragraph 7) was considered to be inadequate due to the lack of documented reviews and corrective actions resulting from vendor information bulletins and 10 CFR Part 21 reports. For example, the Conval, Inc., 10 CFR Part 21 report of October 11, 1982, including licensee records of review and corrective actions, could not be retrieved. Conval valves are installed in the main feedwater and steam systems at Surry (primarily 3/4 to 1 1/2 inch manual valves). The licensee recalled replacing one drain valve on the main steam system which may have been manufactured during the February 1981 - August 1982 period in question. Although adequate procedures appear to have been implemented (e.g., ADM-72 and -93) for identifying and reporting defects discovered at the station, adequate measures (procedures) have apparently not been established to assure that vendor identified conditions that may be adverse to quality

are properly identified and corrected. This is a violation of Criterion XVI of Appendix B to 10 CFR 50 (280,281/86-02-02).

b. Paragraph 6.f in the VPB inspection report concerned a Westinghouse Technical Bulletin (84-06) to verify the adequacy of Auxiliary Feedwater (AFW) flow under normal as well as accident conditions (105 gpm minimum to each SG). The inspectors observed that each of the three AFW pumps could deliver 250 to 300 to each steam generator at approximately 950 psig. This item is closed.

7. Review of Open Items and IE Bulletins

(Closed) Open Item (280/85-01-06) concerned the completion of outstanding items from the cold weather protection periodic test (PT-52) prior to the arrival of winter. PT-52 was performed in the fall of 1985 on October 20th and again on December 12th to verify that identified items had been corrected. This item is considered closed.

(Closed) Open Item (280/85-01-07) concerned discrepancies on electrical distribution documentation found during inspection subsequent to a reactor trip. TV-DA-100 was deleted from Vital Bus feeder breaker 13 documentation (pen and ink change). This item is considered closed.

(Closed) Open Item (281/84-20-03) concerned the normal instrument leads from the reactor trip breaker cubicle not being used for testing of the Unit 2 'B' breaker due to the installation of the bypass breaker in the main reactor trip breaker cubicle (and vice versa). The bypass breaker was subsequently returned to the adjacent bypass cubicle and the normal instrument leads are currently used for testing. This item is considered closed.

(Closed) IE Bulletin 78-04, "Environmental Qualification of Certain Stem Mounted Limit Switches Inside Reactor Containment," is considered closed for Surry Units 1 and 2. The limit switches were replaced with environmentally qualified components in accordance with IE Bulletin 79-01B.

8. Plant Physical Protection

a. Gates and doors in protected and vital area barriers were closed and locked when not attended.

b. Isolation zones described in the physical security plans were not compromised or obstructed.

c. Personnel were properly identified, searched, authorized, badged and escorted as necessary for plant access control.