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

Report Nos.: 50-338/91-26 and 50-339/91-26

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

Docket Nos.: 50-338 and 50-339 License Nos.: NPF-4 and NPF-7

Facility Name: North Anna 1 and 2

Inspection Conducted: November 3, 1991 - December 7, 1991

Inspectors: G. Belisle For 1-6-92
M.S. Lesser, Senior Resident Inspector Date Signed

G. Belisle For 1-6-92
D.R. Taylor, Resident Inspector Date Signed

Approved by: P. Fredrickson 1/6/92
P.E. Fredrickson, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine inspection by the resident inspectors involved the following areas: operations, maintenance, surveillances, operational event followup, licensee event report followup, and action on previous inspection findings. Inspections of licensee backshift activities were conducted on the following days: November 3 and 17, 1991.

Results:

In the area of operations, a violation was identified which involved unlocked valves on the containment hydrogen analyzer and the process ventilation system (paragraph 3.c and 3.e).

In the area of surveillances, a violation was identified involving the use of a procedure that had not been properly reviewed and approved for the conduct of the flow balance testing on an operable safeguards area ventilation system. Additionally, an Activity Screening Checklist was not performed prior to test initiation to ensure that an unreviewed safety question was not involved (paragraph 5.b).

In the area of engineering, weaknesses were identified involving the licensee's engineering evaluation which would allow 2 out of 60 diesel generator battery cells to be jumpered (paragraph 3.d).

In the area of maintenance, the licensee approved a new post-maintenance testing program which uses a computer generated matrix and shifts the decision making process from operations to maintenance planning. The program should provide for more consistency and allow for better tracking of outstanding work items during outages (paragraph 4.b).

In the area of safety assessment and quality verification, the licensee's response to a deficiency in the estimated critical position curves was considered good. Operators took conservative actions upon discovery of the problem during a reactor startup and Corporate Nuclear Safety conducted a detailed review for corrective action (paragraph 3.a).

In the area of surveillance, after a failure of the steam dump control system on Unit 2 that caused a safety injection in September 1991, the licensee conducted a test on Unit 1 to demonstrate operability of the steam dump control system. The test was considered extensive, well controlled, and received sufficient oversight. This action is considered a strength in the surveillance area. The test also identified additional minor equipment problems (paragraph 5.c).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

L. Edmonds, Superintendent, Nuclear Training
R. Enfinger, Assistant Station Manager, Operations and Maintenance
J. Hayes, Superintendent of Operations
D. Heacock, Superintendent, Station Engineering
*G. Kane, Station Manager
*P. Kemp, Supervisor, Licensing
W. Matthews, Superintendent, Maintenance
D. Roberts, Supervisor, Station Nuclear Safety
D. Schappell, Superintendent, Site Services
R. Shears, Superintendent, Outage Management
*J. Smith, Manager, Quality Assurance
A. Stafford, Superintendent, Radiological Protection
*J. Stall, Assistant Station Manager, Nuclear Safety and Licensing

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

NRC Resident Inspectors

*M. Lesser, Senior Resident Inspector
*D. Taylor, Resident Inspector

*Attended exit interview

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

2. Plant Status

Unit 1 operated the entire inspection period at 100 percent power.

Unit 2 started the period operating at 100 percent power. On November 3, operators noticed an increased flow into the Unit 2 primary drain transfer tank, a decreasing volume control tank level and an increase in normal charging flow. Temperature sensing elements indicated valve packing as the source of the leak. The leak rate was estimated at 20 gpm, requiring the licensee to enter the Technical Specification action statement for excessive reactor coolant system identified leakage. Containment entries were made to locate the leaking packing gland, by measuring individual gland leakoff line temperatures. On the second entry, the leak was identified as a packing failure of 2-RH-MOV-2700, RHR suction isolation valve. The leak rate increased to 25 gpm, an Unusual Event was declared and a power rampdown commenced. The unit was shutdown and entered mode 3. The plant was cooled down to 330F and 400 psig to conduct repairs (see paragraph 4.b). After repairs, the unit was restarted on November 5, and operated at full power for the remainder of the inspection period.

3. Operational Safety Verification (71707)

The inspectors conducted frequent visits to 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 TS and to maintain awareness of the overall operation of the facility. Instrumentation and ECCS lineups were periodically reviewed from control room indications 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. Selected reports were followed to ensure that appropriate management attention and corrective action was applied.

a. Reactor Criticality Below ECP

On November 5, during Unit 2 reactor startup, the licensee's graph of 1/M plots as directed by procedure 2-OP-1.5, Unit Startup from Mode 3 to Mode 2, indicated criticality would be achieved with a critical rod position outside the +/- 400 PCM tolerance for the lower and upper administrative limits. The reactor operators suspended rod pulls until the cause of the discrepancies could be determined. During the pursuing investigation, the reactor engineer immediately contacted personnel from NAF, at which time discussions focused on the power defect factor as obtained from station curve 2-SC-3.8. The curve was generated using a two dimensional computer code that did not take into account the reactivity redistribution effect. For the core conditions at the time, reactivity redistribution was estimated by NAF at a positive 300 PCM. Additionally, the STA reverified the rate of positive reactivity due to xenon. A positive 90 PCM could be attributed to xenon decay because of criticality being achieved at a later time than anticipated. The positive reactivity added due to these factors explained the discrepancy. After understanding the reasons for taking the reactor critical below administrative limits, the startup was continued as allowed per 2-OP-1.5 step 5.36.2.

The inspectors questioned why the reactivity redistribution factor was not accounted for during the ECP, and was not communicated to the operators prior to startup. Conversations with NAF personnel indicated that reactivity redistribution is a known phenomenon and is actually considered in shutdown margin calculations for conservatism. However, due to limited data for startups, NAF has been reluctant to provide for the factor in the ECP. Reactivity redistribution is caused by the axial distribution of flux in the core. As the core gets older the burnout of fuel in the bottom of the core tends to shift the axial distribution of flux upwards such that at the end of core life, reactivity in the upper core is more predominant. In calculating the ECP a two dimensional model for power defect is used which takes into account radial distribution but not axial effects. The licensee evaluated the method in which the ECP is being calculated and determined that the three dimensional power defect curve should be generated and used in future startups. In addition Corporate Nuclear Safety conducted a review of the startup and determined that the operators took conservative actions.

b. Component Cooling Expansion Joint Cracking

The inspectors reviewed DR N-91-1681, which was written for circumferential cracking of the CC-P-1A discharge expansion joint. The rubber joint exhibited about a 3 inch long, 1/16 to 1/8 inch deep crack in several locations near the base of the arch of the joint. The licensee's investigation into the matter revealed that there is a lateral offset of approximately 7/8 inch between flanges, however, the expansion joint is not designed to be offset. Additionally, the installed joint was about 1/8 inch shorter than the face-to-face dimensions recommended by the vendor.

The inspectors examined the existing joint and other rubber expansion joints in the component cooling water system and noted that the 1-CC-P-1B discharge expansion joint also exhibited a crack. This was brought to the attention of the system engineer who promptly documented the crack on DR N-91-1708. The crack on this joint was located near the base of the flange and was about 3 inches long and 3/16 inches deep. The DR stated that cracking of this type, most often, is the result of over-elongation and lateral misalignment. The inspectors questioned whether or not the cracking represented an operability concern and whether an engineering evaluation was conducted. While no engineering evaluation was conducted, the licensee did contact the vendor who stated that the joint may last one to two years provided that further expansion of the crack does not occur. The system engineer recommended both joints be replaced within 60 days and as an interim measure marked the edges of the cracks and requested operations to check the joints during their routine rounds and to notify engineering if any changes occur.

The licensee scheduled replacement of the 1-CC-P-1A joint. At that time more precise measurements were taken and the flange to flange offset was determined to be only 1/4 inch instead of the 7/8 inch initially reported. When the new expansion joint was received, it exhibited similar cracking to the installed joints. The vendor was contacted, and on December 4 reported to the site. After inspection of both the new joint and the installed joints, the vendor recommended replacement of the 1A expansion joint only, and the installation of two additional control units (restraining rods). Two are currently installed. The B expansion joint cracking was attributed to the manufacturing process and has no effect on function or life of the joint.

The circumventive nature of the crack indicated a stress on the joint from flow forces. The apparent cause of the stress was movement of the pipe from static to operating conditions upon starting 1-CC-P-1A. After the joint is replaced, the licensee will measure the maximum discharge pressure at the joint when starting the pump.

c. H_2 Analyzer Maintenance

The inspectors reviewed the calibration procedure for Unit 1 post DBA H_2 analyzer 1-HL-H_2A-101. During the calibration, I&C technicians found that the temperature switch for the hydrogen analyzer hot box had failed with the hot box heaters on and hot box temperature at 513°F. The excessive temperature caused extensive damage inside of the hot box, and the box was subsequently replaced per IMP-L-1-MISC-02, Instrument Maintenance Procedure Troubleshooting, Repair and Replacement of Failed Components.

During the review for maintenance of this item, the inspectors noted that a seven day LCO for having both Unit 1 and Unit 2 hydrogen analyzers inoperable had been entered. TS 3.6.4.1 requires two independent containment hydrogen analyzers to be operable. The analyzers are shared between units. The action statement allows up to 30 days operation with one analyzer inoperable and 7 days operation when both hydrogen analyzers are inoperable. The inspectors questioned the operator as to why the 7 day versus 30 day LCO had been entered. The operators indicated that for safety reasons, in order to tag-out the heat trace for one hydrogen analyzer, the other unit's heat trace must also be tagged. The inspectors questioned the independence of the analyzer for this condition. Further discussions with I&C personnel concluded that only one of the hydrogen analyzers heat trace had actually been tagged and that the 7 day versus 30 day LCO had been entered because of a misinterpretation of drawings and tag-out for the maintenance. The inspectors considered this a weakness with regards to knowledge of the system.

Following the return of the system to an operable status, the inspectors performed a walkdown of the hydrogen analyzers in the auxiliary building. During the walkdown, the inspectors noted the locking chain ensuring that 1-HC-40 remains locked open, was not installed. The valve is required to be locked open per 1-OP-63A, Valve Check-off Containment Atmosphere Cleanup. Operations was informed, the valve position was immediately verified to be proper and the locking chain was installed. DR-91-1760 was initiated to document the deviation. This is identified as one example of Violation 50-338/91-26-01: Failure to Maintain Valves Locked.

d. Diesel Battery Inoperable

The inspectors reviewed DRs 1831 and 1835 which documented a low EDG battery cell reading and failure to perform compensatory testing because of low cell readings.

On November 26, during the performance of 1-PT-85, Weekly Battery Check, the licensee identified low water level in the 1H diesel battery. After adding water, voltage measurement across cell number 19 read 2.04 volts DC, which is less than category B allowable values for connected cells per TS Table 4.8-3. Note 3 of Table 4.8-3 states that any category B parameter not within its allowable value indicates an inoperable battery. This resulted in EDG 1H being inoperable, however, operations was not immediately notified. As a result, verification of offsite AC power sources as required by TS 3.8.1.1 action (b) and implemented by 1-PT-80, was not performed within the one hour time requirement. The licensee identified this violation once the condition of the battery was reported to operations. The inspectors will followup on this item once the LER is issued.

After identifying the bad cell, the battery was placed on an equalizing charge and the voltage in cell number 19 was raised to just above the TS limits. However, the licensee discussed the degraded condition of the cell with the battery vendor, who recommended the cell be replaced or jumpered. On November 27, safety evaluation 91-SE-JMP-055 was performed to justify and jumper out cell number 19 of the EDG 1H battery. The cell was jumpered out the same day.

On December 4, the inspectors observed performance of 1-PT-86 for the 1H EDG. This test is performed at least once per 92 days to meet TS surveillance 4.8.1.1.3.b. The test verifies that the parameters in table 4.8-3 meet category B limits. During performance of the test, cell 42 was found to have a voltage reading of 2.11 volts. Note 2 of table 4.8-3 states that for any category B parameter(s) outside the limits shown (for voltage ≥ to 2.13 volts), the battery may be considered operable provided that the category B paramenter(s) are within their allowable values (voltage > 2.07) and provided the category B parameters(s) are restored to within limits within 7 days. The licensee initiated an equalizing charge to restore cell voltage. Several other individual cell tages were noted to be considerably lower than their last readings, .en though the average individual cell voltage was higher. The in ectors were concerned with the voltage readings because an equa..zing charge had recently been performed and the battery appeared to be degraded.

The inspectors were informed by the licensee that an evaluation of station and diesel battery availability for battery cell jumpers was performed. The evaluation concluded that the subject diesel battery would be considered operable if up to two cells were jumpered. The safety evaluation for jumpering cell number 19 was based partially on this evaluation.

The inspectors reviewed the safety evaluation and engineering evaluation and had the following concerns:

(1) In determining the operability of the battery with two cells jumpered, the only factor that was evaluated was . battery

capacity test. TS requires battery terminal voltage to be greater than or equal to 129 volts on a float charge. The calculation in the engineering evaluation showed degraded terminal voltage (2 cells jumpered) to be 127.6 volts based on 2.20 volts per cell. This is below the TS limit.

(2) Calculations in the evaluation were based on a capacity test that was performed in 1989. No consideration was given for battery degradation since that time. The inspectors considered that not extrapolating for current battery condition was unconservative.

In addition to the above concerns, the inspectors questioned the magnitude of the individual cell voltages. After jumpering cell 19, individual cell voltages increased as a result of the float voltage remaining near the 60 cell value with only 59 cells active. The vendor recommends maintaining individual cell voltage between 2.15 and 2.22 volts. At the 2.22 volt upper limit, the 129 volts required by TS would not be met for 58 cells. The licensee contacted the vendor who informed them that average cell voltages up to 2.25 volts average were acceptable. This would allow an additional jumper to be installed as long as the safety evaluation could justify it.

The licensee stated they would revise the evaluation if the need for two jumpered cells arose. The licensee also proposed increased surveillance on the battery (weekly checks of all cells). Based on this the inspectors did not have any immediate operability concerns, however, remained concerned with the apparent declining performance of the battery. The inspectors will continue to monitor this issue under IFI 50-339/91-26-03: Jumpered Cell for 1H EDG Battery.

e. Unlocked Valve to Process Vent Blower

On December 4, during a walkdown of the auxiliary building, the inspectors noticed that the installed danger tags isolating the process vent charcoal filter 1B did not have signatures of the independent verifier. The inspectors brought this to the attention of the shift supervisor who informed the inspectors the tags were active per tagout 1-91-GW-0048. The tagging record indicated the certification check had been performed. This condition was promptly corrected. The inspectors considered this as an example of inattention to detail on the part of the auxiliary operator.

During the same walkdown, the inspectors identified valve 1-GW-135, inlet to the 1-GW-F-1A process vent blower, unlocked. A chain was properly placed around the valve's handwheel and connected to the loop of the lock, however, the lock was not engaged. Upon further investigation, the licensee determined that the valve was last positioned correctly and locked on December 3 in accordance with 1-OP-23.3, Process Vent System.

The licensee verified the valve to be correctly positioned, locked the valve and initiated DR 1883 to document the deviation. This was the second valve in two weeks which was identified by the inspectors as not being in its required locked condition. The valve being out of its required condition of 1-OP-23.3 is considered the second example of Violation 50-338/91-26-01, Failure to Maintain Valves Locked.

f. The inspectors reviewed DR 91-1762 which documented a point power plug "patch cord" not installed in jack 1H/11A inside of the Unit 1 Hathaway panel. The plug powered annunciator window 1H-C2, 4KV Emergency Bus 1J ALT Supply Breakers Auto Trip. The condition was discovered by the licensee. The inspectors discussed the DR with the licensee to determine the potential for other annunciators being disabled because of uninstalled power plugs.

In order to support the licensee's policy to maintain a black board annunciator panel, patch cords are pulled inside of the Hathaway panel to disable annunciators which are lit but provide little information to the operators. To disable the annunciator, the licensee administratively controls the unplugged cord by one of three methods. These include unplugging per an operating procedure, tagging for system isolation, or installing a special order tag. Additionally, spare patch cords within the cabinet are labelled as such. These above controls provide a method to identify the reason for unplugged patch cords within the cabinet.

The inspectors examined the inside of the Hathaway panel expecting to see all unplugged patch cords labelled, however, a number were unlabelled. After raising a concern regarding the potential for other annunciators being disabled, the licensee performed an inventory of all unplugged patch cords. One additional patch cord was identified as not being plugged into its associated jack. The remaining unplugged cords were identified as spare. The one unplugged cord provided input to the Unit 1 sequence of events recorder for "RWST High Temperature." The condition was discovered after the RWST High Temperature annunciator alarmed. The licensee indicated the most likely reason for the alarm was due to a short that was caused by a grounded events recorder RWST High Temperatures patch cord. A work request was written to repair the short.

To prevent having unidentified unplugged patch cords in the Hathaway panel, the licensee removed all spare patch cords. The only unplugged cords that remained were labelled as to provide the reason for being unplugged. Additionally, the licensee informed the inspectors that a more formal method for controlling patch cord unplugging was being developed and the licensee was considering performing an inventory inside the panels at some frequency.

Two examples of a violation were identified.

4. Maintenance Observation (62703)

Station maintenance activities were observed/reviewed to ascertain that the activities were conducted in accordance with approved procedures, regulatory guides and industry codes or standards, and in conformance with TS requirements.

a. Post Maintenance Testing Program

The inspectors reviewed portions of the licensee's new PMT program as described in VPAP 2003. The new program was implemented to improve consistency of PMT and to shift test determination responsibility from the Shift Supervisor to the maintenance planning organization. The new program currently applies to safety related mechanical and electrical work activities and a limited number of non-safety related activities. Essentially the program consists of computer stored matrices that cross-reference maintenance actions on components to pre-maintenance actions, verifications and tests. A PMT test data sheet is generated in the planning process which identifies the requirements based upon the projected scope of the maintenance. The matrices were developed by engineering personnel and provisions are in place to require engineering review for any PMT which may warrant a waiver. As the program is in its infancy stages a PMT feedback sheet is also available to allow users to document problems and initiate necessary changes. One feature of the PMT data base is the ability to assign and track the status of multiple PMTs on components. This should be particularly useful during outages for assuring closure of all outstanding work.

b. RHR Suction Valve Packing Failure

The inspectors reviewed licensee actions taken in response to the November 3, packing failure of 2-RH-MOV-2700, RHR suction isolation valve. The failure resulted in a 32 gpm leak on Unit 2 and the subsequent declaration of an Unusual Event and shutdown of the plant. The valve is a 14 inch Copes Vulcan parallel slide gate valve. The packing arrangement is five graphite rings with three braided wiper rings below a lantern ring and two graphite rings with three braided wiper rings above the lantern ring. The lantern ring is located at the packing leakoff line. When the old packing was removed from the valve, very little packing was found below the lantern ring indicating that it had failed, broken up into small pieces and washed out the leakoff line. The valve was repacked in the same manner while the licensee continued to develop its root cause analysis.

Discussions with the packing vendor and review of EPRI Project 2233-3, Valve Stem Packing Improvements, indicated that only three graphite rings in conjunction with two braided wiper end rings should be utilized below the lantern ring and any excess rings should be replaced with a stuffing box bushing. The report stated that deep stuffing boxes filled with packing may actually degrade packing performance because more packing results in additional packing consolidation over time. This causes a decay in gland load and eventual leakage. The licencee is considering this along with the possibility of converting the valve to live-load packing.

The licensee's investigation identified concerns with the corresponding Unit 1 RHR valve in that EWR 85-517 was written to install the stuffing box bushing along with live-load packing. A review of the work history shows this bushing was later apparently removed and replaced with packing rings without addressing the EWR. The licensee noted that the recent packing performance of the Unit 1 valves has been very good and probably attributed to live-load packing. It appeared that the bushing was removed after implementation of the EWR due to excessive packing leakage. It is, therefore, not clear to the licensee which combination of a stuffing box bushing and live-load packing should be used to provide the highest degree of reliability. The licensee believed that the live-load packing had not previously been used on the Unit 2 RHR valve because of interference from the stem anti-rotation device. Inspector followup will be performed under LER 50-339/91-11.

No violations or deviations were identified.

5. Surveillance Observation (61726)

The inspectors observed/reviewed TS required testing and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that LCO's were met and that any deficiencies identified were properly reviewed and resolved.

a. Hydrogen/Oxygen Analyzer Calibration

On November 19, the inspectors observed calibration of the waste gas decay tank hydrogen/oxygen analyzer using instrumentation procedure ICP-GW-1-H2-102. The procedures uses sample gasses at various percentages of hydrogen concentration to calibrate the instrument. The technician pointed out to the inspectors that the hydrogen concentration meter does not give the actual hydrogen concentration. Since the instrument responds logarithmically and the meter is linear, a curve must be used to convert the known concentration of hydrogen to the expected meter reading for calibration purposes.

Since the instrument is also used by control room operators for determining hydrogen concentration in the WGDT, station curve 1-SC 6.2 provides the conversion information. The fact that a curve was needed to convert meter readings to actual readings indicated that the design was not sufficiently human factored. It should be noted that a recent TS amendment no longer requires the hydrogen portion of the instrument to be operable. The licensee indicated that the instrument would be reviewed to determine if enhancements would be appropriate.

b. Safeguards Area Ventilation System Flow Balance

On November 24, the inspectors witnessed the licensee conduct a flow balance test on the Unit 2 safeguards area ventilation system. The test was initiated in response to NRC concerns regarding lack of administrative controls over ventilation dampers in the system. (IFI 50-338/90-30-02). The inspectors noted that the procedure being used to perform the test had not been formally reviewed and approved by appropriate personnel including the SNSOC. Test personnel explained that the test procedure was a supplement of write-in steps to a generic acceptance test 0-NAT-M-001, Mechanical Functional Loop Checkout. Although the Shift Supervisor had authorized testing and 0-NAT-M-001 had been approved by SNSOC, the inspectors remained concerned that the specific steps written for testing the ventilation system had not been properly reviewed or approved.

Based on this concern, the inspectors reviewed EWR 90-381 which was written on October 24, 1990, after dampers in the cubicles for the Unit 1 RS pumps were found to be closed or nearly closed. The EWR identified the need to balance the system to the design flow rates and place controls on the dampers to preclude future misalignment. Additionally, relief dampers had been found open and it was not clear to the licensee what function these dampers performance or what their position should normally be. Licensee initial actions were to open the cubicle dampers, close the relief dampers and obtain air flow values. The values were determined to be inconsistent with design flows. A periodic test procedure assured that the minimum exhaust flow was present to ensure a negative pressure in the building, however, assurance of individual motor cooling might not be adequate. Section 9.4.6.4 of the UFSAR states that the system was balanced, adjusted and tested upon installation; however, the licensee was unable to produce the pre-operational test which balanced the system. Based on this, the November 24 test was conducted.

As this test appeared to be a functional test, the inspectors reviewed the administrative controls for testing. Administration Procedure 5.29, Acceptance Testing Procedure Format, and 0-NAT-M-001 imply that the acceptance test program is used for functional checkout of systems following modifications prior to returning the systems to service. In this case, the safeguards area ventilation system had not been removed from service and was considered operable during the test. It appears that using write-in steps under the licensee's acceptance testing program was inappropriate for the flow balance test. The flow balance testing was intended to set and/or verify the system flow and did not involve a modification. Additionally, it was not clear to the licensee exactly what testing program should have been used, i.e., periodic, surveillance or post maintenance.

TS 6.8.2 requires surveillance and test procedures to be reviewed and approved by SNSOC prior to implementation. Administrative Procedure

VPAP 0102, Station Nuclear Safety and Operating Committee, implements this requirement. In addition ADM 3.7, Engineering Work Requests, requires Station Engineering to prepare an Activity Screening Checklist to establish whether a test requires a safety evaluation. The inspectors determined that an Activity Screening Checklist was not completed. The inspectors did not consider that these requirements were met for the conduct of this test. The failure to follow VPAP 0102 and ADM 3.7 are collectively identified as Violation 50-339/91-26-02: Failure to Maintain Adequate Controls Over Safeguards Area Ventilation Test.

c. Steam Dump Functional Check

On November 26, the inspectors observed performance of 1-IMP-MS-7-408, Functional Check of Condenser Steam Dump System. The inspectors attended the pre-test briefing and observed the test from the control room, steam dumps and process cabinets. The test was developed to check the steam dump system cor 's on Unit 1 and was performed as part of the licensee's correct :tion in response to Unit 2's September 20, 1991, reactor trip and subsequent safety injection. The SI signal in the Unit 2 event resulted from a malfunction in the steam dump control system tht caused a high steam flow with low-low reactor coolant Tave.

The test was performed by isolating the steam dumps, generating control signals at the primary plant process cabinets and verifying proper operation of the steam dumps. The procedure performs functional checks of both the turbine trip and load reject modes of operation. When initially applying the DC input (demand signal) at the process cabinets, no output signal was generated as evidenced by the lack of change in the demand indicator or dump valve position. The I&C technicians conducting the test replaced the DC source and an extender card which had been installed for the test. These actions temporarily corrected the malfunction and the turbine trip portion of the test was completed. When setting up for the load reject part of the test, the technicians noted difficulty in reinstalling the system card in slot C8-572. The test recommenced, but again no output signal was being generated. A closer look at slot C8-572 identified a broken card edge connector internal to the cabinet. The broken connector was the most likely cause of being unable to obtain an output signal initially. The faulty connection prevented circuit continuity and precluded steam dump modulation in the Tave or steam pressure mode. The test was stopped to replace the broken connector. After the connector was replaced, on the following day the functional checks were completed and the steam dumps were returned to operational status.

In addition to the above deficiency, other equipment problems were identified. These problems were documented by DR's 1829, 1839 and 1842. The equipment problems included a broken air line to the control positioner for steam dump valve "G" which prevented valve operation in the modulation mode, a failed summing amplifier C8-555, and card, C8-553 out of calibration. The licensee noted that the card failure could have been a result of reenergizing the circuits that were isolated following maintenance.

During performance of the test and subsequent maintenance, the inspectors observed positive control of the evolutions. The licensee closely monitored plant parameters, and licensee management oversight was evident. The inspectors considered the test a strength with regards to positive corrective action to the September 20, safety injection event. Following completion of the test the licensee indicated the procedure would be improved prior to its performance on Unit 2. The licensee intends to conduct this test at some regular frequency, yet to be determined.

d. Turbine Valve Freedom Test

On November 15, the inspectors observed the performance of 1-PT-34.3, Turbine Valve Freedom Test from the control room. The test verified proper operation of the turbine throttle valves, governor valves, reheat stop valves, and intercept valves. The test is required by TS 4.7.1.7.2(a) to be performed at least every 31 days. Each valve is cycled closed by control room operators while personnel are stationed locally to visually observe valve operation. During the test, the closed light for number [illegible] right reheat and intercept valves, at the turbine control panel did not light, however, the valves were locally verified closed. The test procedure does not require a check of the closed lights for these valves but rather requires local verification. The operators informed the inspector that the closed light would be checked. No other problems were noted, and all valves responded as expected.

One violation was identified.

6. LER Followup (92700)

The following LERs were reviewed and closed. The inspector verified that reporting requirements had been met, that causes had been identified, that corrective actions appeared appropriate and that generic applicability had been considered. Additionally, the inspectors confirmed that no unreviewed safety questions were involved and that violations of regulations or TS conditions had been identified.

(Closed) LER 50-338/90-01: Reactor Trip Due to a Failed Driver Card on a Feedwater Regulating Valve.

The event involved a reactor trip on January 23, 1990, due to a failed Westinghouse 7300 printed circuit driver card in the "C" main feedwater regulating valve controller. The root cause analysis performed by the licensee determined that the power supply transistor 2NS189 had failed. Additionally, a review of the Unit 1 equipment history that covered

Westinghouse 7300 printed circuit driver cards identified that three other driver cards associated with main feedwater regulating valves electronic circuits had failed between September 1989 and January 1990. The cards had all been energized for approximately 10 years before they failed.

As part of the corrective action, the licensee identified similar Westinghouse 7300 driver cards whose failures would lead to a reactor trip. As a result, new driver cards were installed on Unit 1 and Unit 2 feedwater regulating valve control circuits and a PM was initiated to replace the cards on a 5 year frequency.

On September 20, 1991, a reactor trip on Unit 2 was caused by a failed driver card similar to those discussed above. The failure occurred in one of the new cards. Further discussion with the licensee indicated that purchasing new cards was somewhat misleading in that the cards may have been in a warehouse for up to 6 years. Additionally, new driver cards purchased, installed and calibrated in Unit 2 during the 1990 outage were only 67 percent reliable. The licensee has their own module repair program and is continuing to try to increase the reliability of the Westinghouse 7300 cards. For example, the licensee has initiated a maintenance and calibration tracking and trending program to record maintenance and failure rates of serialized equipment. The licensee has held meetings with Westinghouse on the 7300 card reliability concern. The inspectors will continue followup on this matter when evaluating LER 50-339/91-09 which reports the corrective action for the Unit 2 reactor trip of September 1991.

7. Action on Previous Inspection Items (92701, 92702)

   a. (Closed) Violation 50-338/91-06-02: Failure to Follow or Use Procedures During Maintenance and Surveillance on the Personnel Airlock Door.

      The violation involved failure to follow procedures during troubleshooting of the personnel airlock door limit switch, failure to properly record the results of unsatisfactory leak test results on the door and maintenance completed without authorization. The licensee responded to the violation in correspondence dated May 10, 1991. Corrective action included personnel counselling by management and training on requirements for maintenance activities during non-normal work hours.

   b. (Closed) Inspector Followup Item 50-339/91-10-02: Potential to Damage Limitorque Actuator Wires When Replacing Switch Cover.

      The licensee responded to a concern raised by the inspectors regarding installation of cover plates on the Limitorque SMB-000 series of MOV's. The compacted nature of wires in the limit switch box is such that the potential exists for damage during assembly. The licensee stated that, due to the impractical nature of the test, post-maintenance testing does not check each electrical circuit.

Operability is confirmed, though, because essential control and indication functions are verified when the valve is stroked. The licensee recognizes the potential problem and has emphasized in training the need for exercising care during this particular action.

c. (Closed) URI 50-338/91-16-02: Quench Spray Instrumentation Not Calibrated Within Required Time Frame.

This item involved a missed instrumentation calibration as a result of a computer generated PM schedule not being properly maintained. The problem resulted when personnel assigned to perform the last PM took credit for a calibration performed about a year earlier because of corrective maintenance, but failed to update the PM data base to reflect a new due date. To correct the problem, the licensee issued standing order MDSO 01-001 which requires a PM due date change request to be filled out whenever credit is taken for a PM which has been performed at an earlier date because of corrective maintenance. In addition, to determine if this problem was wide spread, the licensee performed a sampling of mechanical, electrical and I&C PMs. Of 25 mechanical and electrical components sampled, no similar problems were identified. However, 25 instruments were sampled and one additional instrument was identified as being out-of-calibration for the same reason.

Through further discussion with the licensee, the inspector was informed that all I&C PMs had been examined and an additional 12 were identified that would have exceeded their due dates. The late PMs were identified while still in their grace period. The corrective action appears to be adequate to preclude recurrence of missed PMs because of inaccurate computer data bases.

8. Exit Meeting (30703)

The inspection scope and findings were summarized on December 6, 1991, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results listed below. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection. Dissenting comments were not received from the licensee.

Item Number	Description and Reference
VIO 50-338/91-26-01	Failure to Maintain Valves Locked (paragraph 3.c and 3.e)
VIO 50-339/91-26-02	Failure to Maintain Adequate Controls Over Safeguards Area Ventilation Test (paragraph 5.b)
IFI 50-338/91-26-03	Jumpered Cell for 1H EDG Battery (paragraph 3.d)

9. Acronyms and Initialisms

ALT	Alternate
CC	Component Cooling
DBA	Design Basis Accident
DC	Direct Current
DR	Deviation Report
ECCS	Emergency Core Cooling System
ECP	Estimated Critical Position
EDG	Emergency Diesel Generator
EPRI	Electric Power Research Institute
EWR	Engineering Work Request
GPM	Gallons Per Minute
I&C	Instrumentation and Calibration
IFI	Inspector Followup Item
KV	Kilovolt
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MDSO	Maintenance Department Standing Order
MOV	Motor Operated Valve
NAF	Nuclear Analysis and Fuel
NRC	Nuclear Regulatory Commission
1/M	Inverse Multiplication
PCM	Percent Millirho
PM	Preventive Maintenance
PMT	Post Maintenance Testing
PSIG	Pounds Per Square Inch Gage
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RS	Recirculation Spray
RWST	Refueling Water Storage Tank
SI	Safety Injection
SNSOC	Station Nuclear Safety and Operating Committee
STA	Shift Technical Advisor
TAVE	Average Temperature
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VIO	Violation
VPAP	Virginia Power Administrative Procedure
WGDT	Waste Gas Decay Tank