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

Report Nos.: 50-338/92-29 and 50-339/92-29

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 22 - December 19, 1992

Inspectors: Stephen Jurjen For 1/13/93
M. S. Lesser, Senior Resident Inspector Date Signed

Steph Jurjen For 1/13/93
D. R. Taylor, Resident Inspector Date Signed

Approved by: [signature] for 1/13/93
M. V. Sinkule, Branch Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine inspection by the resident inspectors involved the following areas: operations, maintenance, minor modifications, surveillances, and action on previous inspection findings. Inspections of licensee backshift activities were conducted on the following days: November 25 and December 6, 8 and 17, 1992.

Results:

In the area of maintenance/surveillance, the licensee identified that nuclear instrument testing has not been performed in accordance with technical specifications. The licensee's corrective action involves testing the channel while it is tripped at one point and bypassed during another point. In that the licensee may be testing more functions than the minimum required by the technical specification, this may conflict with NRC policy regarding the use of limiting condition for operation action statements for testing and maintenance during reactor operation. Adequacy of this methodology remains under review and was identified as an unresolved item (para 6.c).

In the area of maintenance, the reliability centered maintenance program was reviewed. Controls to improve the implementation process were recently instituted and the program appears to be getting back on track (para 4.a).

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In the area of maintenance/surveillance, the licensee has replaced 77 of 83 Klockner Moeller 480 volt circuit breakers due to a Part 21 concern. The replacement program was evaluated as a strength (para 7.b).

In the area of engineering/technical support, a system engineer's alert review of motor operated valve test data identified that the results had not been adequately evaluated. The review was not programmatically required and was a good example of an engineer's efforts to maintain awareness of system status. Further detailed evaluation was performed and properly documented (para 4.c).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*M. Bowling, Manager, Nuclear Licensing and Programs
*M. Crist, Supervisor, Station Procedures
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
J. O'Hanlon, Vice President, Nuclear Operations
D. Roberts, Supervisor, Station Nuclear Safety
*R. Saunders, Assistant Vice President, Nuclear Operations
D. Schappell, Superintendent, Site Services
R. Shears, Superintendent, Outage and Planning
*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
*S. Lee, Senior Materials Engineer

*Attended exit interview

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

2. Plant Status

Unit 1 continued to operate in end-of-life coastdown ending the inspection period at 45% power.

Unit 2 operated the entire inspection period at 100% power.

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 TSs 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. Mis-labelled Valves

On November 23, the licensee identified that the isolation valves on the two fuel oil supply lines (1-EG-303 and 306) to the 1J EDG Day Tank were reverse labelled. The condition was determined when operators were unable to drain the supply line from the 1JA fuel oil transfer pump after the tagout was supposed to have isolated the line. The day tank is supplied by two redundant fuel oil transfer pumps (1JA and 1JB) via redundant supply lines. The licensee had tagged out the 1JA pump to install a discharge flow rate instrument. Due to the mislabelling, the 1JA suction valve and the 1JB pump supply line isolation valve were tagged, which unknowingly rendered the 1J EDG inoperable.

Upon discovery, the licensee immediately cleared tags and restored the system to an operable status. The total time of inoperability was approximately 2 hours.

The inspectors verified that the 1H EDG and other safety systems remained operable during the time frame, thus, the event occurred within the TS allowable outage time. The inspectors additionally reviewed several past maintenance activities on the fuel oil system and the associated tagouts including the 1JA pump replacement of May 1991 and the fuel oil storage tank cleanings in 1990. It was determined that the tagouts and valve alignments did not render the EDG or the fuel oil system inoperable. Over the next several days, the licensee performed flow testing to verify system configuration and no other problems were identified.

The inspectors questioned the effectiveness of the licensee's configuration management program since the fuel oil system had been recently walked down and re-labelled. The supply lines cannot be traced directly from the fuel oil transfer pumps because portions of it are buried, however, station yard drawing 11715-FB-4A shows the piping layout. The licensee's re-labelling program (configuration management) does not require review of station yard drawings for buried piping if the component has previously been labelled and has a valve lineup procedure associated with it.

b. Use of TS 3.6.2.2

On December 9, the licensee identified a concern involving relay testing where automatic start of an outside recirculation spray pump and its associated casing cooling pump are simultaneously rendered inoperable for less than one minute. TS 3.6.2.2 does not specifically address this combination of inoperability and, therefore, the licensee considered that TS 3.0.3 should apply during this portion of the test. The licensee pointed out that the safety function of the system is maintained by the opposite train recirculation and casing cooling pumps. However, the casing cooling pump provides NPSH for the outside recirculation spray pump and, as such, is a supporting component. The train is inoperable with either of the pumps non-functional. The licensee concluded that the TS is poorly worded. The TS LCO, in part, requires two outside recirculation spray pumps and two casing cooling pumps be operable. It provides an action statement if either a recirculation spray pump or a casing cooling pump is inoperable, rather than an action statement for an inoperable subsystem or train - both pumps simultaneously inoperable.

The licensee intends to submit an LER for the concern. The relay testing will continue as before and the licensee will voluntarily enter TS 3.0.3 during that period. The licensee will also submit a TS amendment request in a timely manner to clarify the requirement.

The inspectors reviewed the NRC Inspection Manual Part 9900 on the subject of voluntarily entering TS 3.0.3. The inspectors also discussed the issue with the NRR project manager and regional management, and determined the licensee's plans to be acceptable.

c. Turbine Control System

On December 17, the Unit 1 main turbine control system shifted from "operator automatic" to "turbine manual-impulse-in" without operator action. About 2 hours later, the operators noted a 10 MW drop in load. The operators took action to control any further load decrease and after stabilizing, shifted the turbine control system to "manual-impulse-out" control. At that time, an additional operator was assigned to the control board until the cause for the turbine control system response could be determined. A short time later, the control system again shifted back to "impulse-in" without operator action. The operators shifted back to "impulse-out", but within a few minutes, the control system shifted back to "impulse-in". The operators continued to closely monitor the turbine control system while the malfunction was being evaluated.

The instrument shop's evaluation identified two potential control cards which, if failed, could affect the turbine control system in the manner described. One of the control cards was replaced and the turbine control system returned to "impulse-out". The system remained in "impulse-out" for the remainder of the night with an additional CRO assigned to the control board. On December 18, the turbine was returned to "operator automatic" and the additional operator secured. The inspectors considered the licensee's action to provide for additional licensed operator monitoring of the turbine control system to be conservative and appropriate.

No violations or deviations 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. Reliability Centered Maintenance

The inspectors met with licensee representatives to review the development and implementation status of the RCM program. The program is described in Corporate Department Administrative Procedure 2, Preventive Maintenance Upgrade Program. The purpose of the program is to evaluate PM requirements based upon component functional importance, historical reliability and economic return with objectives of reducing system unavailability and corrective maintenance, and prioritizing maintenance resources. The licensee has been developing the RCM program for a few years, however, only recently established improved controls to prioritize and implement maintenance recommendations.

RCM evaluations are first performed on each plant system of interest. Components within a system are then categorized according to relative significance in achieving RCM objectives. Failure modes and effects are analyzed. Maintenance histories, vendor data and several other sources are reviewed to determine component reliability and adequacy of PM requirements. The evaluation and recommendations are documented in the Maintenance Based Summary Index.

Recommendations for PM changes are then prioritized to assure that those having the most immediate effect will be implemented first. The implementation process establishes the method by which the recommendation is implemented, i.e., via a procedure change, frequency change, engineering task, etc. The implementation process status is tracked through completion. The inspectors determined that only two systems (Charging and Rod Control) had all of the Priority 1 recommendations implemented. The evaluations of several other systems such as AFW, SW and EDG have been completed since mid-1991 but the recommendations have not been implemented. The licensee attributed this to lack of a prioritization and implementation plan when the evaluations were completed. Following development of the plan, the more recently completed systems were moved directly through to implementation. The licensee's goals are to complete implementation of the Priority 1 recommendations by June 1993.

The licensee discussed several examples of the more significant RCM recommendations. These include:

- increased reliance on motor/pump oil sampling rather than scheduled oil changes
- reduced frequencies of diesel engine teardowns
- reduced frequencies of manual valve lubrications
- improved PM on heat tracing to reduce failures

Additionally, the licensee intends to rely more heavily on thermography scanning of equipment instead of teardowns.

b. Bottled Air System Maintenance

On December 10, 1992, the inspectors witnessed maintenance on the control room bottled air system per WR 850610 and procedure 0-MCM-1006-01, Repair of Safety Related Piping and Component Bolted Flange Joints. The maintenance was being performed because of an air leak on an inline orifice. The flange connection was unbolted, inspected and a new gasket installed. The inspectors verified that the appropriate TS action statement was entered and that requirements and signoffs were met. The maintenance was completed and the system returned to service the same day. No problems were identified.

c. Charging System Valve Maintenance

On December 11, the inspectors observed troubleshooting of 02-CH-MOV-2286A, charging pump discharge valve for the Unit 2 1A charging pump. The troubleshooting was in response to DR 2094, dated November 18, which documented that the MOV was returned to service without evaluation of high motor current in accordance with EWR 92-142. The EWR requires an engineering evaluation for currents 20% greater than nameplate. The nameplate motor current was 2.8 amps. The actual closing current was 4.0 - 4.5 amps and opening was 3.7 - 3.9 amps. The engineer did not perform the evaluation for 02-CH-MOV-2286A because an evaluation done a year earlier was noted to have approximately the same currents. The DR was written because more stringent requirements were in effect for evaluating high motor currents. Further engineering analysis is required for motors with operating currents greater than 20% of nameplate.

The analysis for 02-CH-MOV-2286A included troubleshooting which was performed per WR 815362 using "skill of the craft". The valve was cycled by hand to identify any binding, followed by running the motor uncoupled from the valve actuator to measure currents. The current drawn by the motor in both the open and closed directions was similar to the opening current when the motor was coupled to the actuator (3.7 - 3.9 amps). Per a discussion with the maintenance engineer, these values were expected. The additional current for closing the valve with the motor coupled to the actuator was attributed to overcoming system pressure. Following testing, the maintenance engineer submitted an EWR addendum for Design Engineering to evaluate the existing current against the motor temperature curves to ensure that the life of the motor will not be impaired by continued operation.

The inspectors noted that the DR which documented the high currents was initiated because of a system engineer's independent review of maintenance test data. The inspectors considered this review, which is not required of system engineers, to be a good example of a system engineer maintaining awareness of relevant system changes and status. The evaluation for the valve motor demonstrated the motor to be operable for its design life.

No violations or deviations were identified.

5. Minor Modifications (37828)

70% Project Review, Unit 2, DC 89-41-2

On November 23, the inspectors attended the 70% project review meeting for DC 89-41-2, RTD Bypass Line Elimination Project - Unit 2. The meeting had been previously scheduled, but was canceled due to poor attendance and a lack of comments. The inspectors noted that this meeting was very brief with several in attendance unprepared to ask questions or comment on the package. The inspectors discussed the apparent lack of preparation for the meeting with the project engineer. The project engineer stated that he did not expect a significant number of comments because of the similarities between this DC and the Unit 1 DC. The Unit 1 DC is scheduled for implementation starting January 1993, and has already gone through the DC approval process. The inspectors considered the meeting to be a poor example of implementing VPAP-301, Design Change Process, for a 70% Project Review. VPAP-301 requires a project review meeting at the station after issuance of a 70% draft DCP. The purposes of the meeting are to: 1) review the design change; 2) obtain input from the project team; 3) discuss any of the station's concerns and any proposed resolutions; and 4) discuss station responsibilities for installation, operation, and maintenance.

No violations or deviations were identified.

6. 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 LCOs were met and that any deficiencies identified were properly reviewed and resolved.

a. RCP Bus UF Test

On November 24, the inspectors witnessed UF protection channel functional testing of the Unit 2 RCP buses. The licensee used procedure 2-PT-33.10(11)(12), Reactor Trip System Functional Test for RCP 2A(B)(C) Underfrequency. There is one UF relay for each of the three RCP buses and the tests verify that each relay activates one at a time when a test signal is applied. The test was thorough and adequately verified operability including alarm and trip functions. The inspectors noted good communication between the control room and the instrument racks as headset phones were used. Also, good self-checking and verification techniques were observed.

b. Reactor Trip Breaker and Solid State Protection Testing

On December 17, the inspectors witnessed the licensee perform 2-PT-36.1A, Reactor Protection and ESF Logic Train A. The inspectors verified that the procedure requires the reactor trip bypass breaker to be tripped with the local manual shunt trip prior to placing it in service as required by TS 3.3.1.1. The procedure was annotated to advise the Shift Supervisor of equipment, such as the 2H EDG and SW pump 2-SW-P-1A, which would be rendered inoperable during the test. The test was well controlled by a technician in the control room, who used headsets to communicate with technicians at the instrument racks.

c. Power Range Nuclear Instrument Testing

On December 3, the licensee identified a potential violation of TSs involving surveillance testing of the PRNI. TS 3.3.1.1 requires a monthly channel functional test of each instrument. The licensee conducts the test using 1(2)-PT-30.2 which disconnects the detector input signals from the instrument drawer, rendering the channel inoperable (bypassed) without placing the channel into a tripped condition. This is done to check both the high setpoint (109%) and the low setpoint (25%) since the test circuit can only superimpose a test current onto an operable detector's output. The TS, in part, requires an inoperable channel to be placed in a tripped condition within 1 hour, however, the licensee identified that the test has taken up to 2 hours to complete without placing the channel in "trip."

The inspectors reviewed the licensee's corrective action which revised the test procedures. The channel is placed in a tripped condition by removal of the control power fuses prior to disconnecting the detector input signals. Later, the control power fuses are replaced to facilitate testing of the power range drawer status indications and the trip bistables. During this portion of the test, the channel is bypassed without a channel tripped condition in effect. The procedure has a caution statement to limit this part of the test to less than 1 hour in order to comply with TS Action 2.

The inspectors developed several concerns with the corrective action:

1. The test is not being performed as described in the UFSAR section 7.2.2.2.1.6 which states:

> The power range channels of the nuclear instrumentation system may be tested by superimposing a test signal on the actual detector signal being received by the channel at the time of testing. The output of the bistable is not placed in a tripped condition prior to testing. Also, since the power range channel logic is two out of four, bypass of this reactor trip function is not required.
>
> It should be noted that a valid trip signal would cause the channel under test to trip at a lower actual reactor power level. A reactor trip would occur when a second bistable trips. No specific provision has been made in the channel test circuit for reducing the channel signal level below that signal being received from the nuclear instrumentation system detector.

2. The UFSAR also states that "bypassing" a channel for testing is only required for one-of-two protection logic (source and intermediate range). This appears to be consistent with TS action 2.b. which would only allow "bypassing" a PRNI channel if it has previously been placed in "trip" due to inoperability and a second PRNI channel needs to be surveillance tested; a rarely encountered condition. The licensee did not perform a 50.59 safety evaluation for this change in testing procedure.

3. The licensee did not consider the additional requirements of TS Action 2 with an inoperable channel. These require power to be restricted to $\leq$75% and PRNI setpoints to be reduced to $\leq$85% within 4 hours or monitor Quadrant Power Tilt Ratio at least once per 12 hours with the moveable incore detectors.

The licensee believes they are required to test the low setpoint by the TS (although it is blocked at ≥10% power) and can only do this completely by placing the channel in bypass. The licensee indicated that quarterly channel calibration can only be done over the entire range of the instrument by disconnecting the detector and that on-line testing would only be able to calibrate the portion of the range above actual reactor power.

The inspectors reviewed the monthly functional test procedure and determined that it checks more functions of the instrument than the minimum required by TS, such as the P8 and P10 permissives and overpower rod stops. It is clear that the licensee's intent has been to develop a comprehensive test procedure. However, since the instrument is required to be out of service to do some of these checks, the procedure appears to conflict with recent NRC policy contained in Generic Letter 91-18 and NRC Inspection Manual Part 9900, Maintenance - Voluntary Entry into Limiting Conditions for Operation Action Statements to Perform Preventive Maintenance. TSs permit entry into LCO action statements to perform surveillance testing for a number of reasons. One reason is that the time needed to perform the task is usually only a small fraction of the allowable outage time specified in the action statement. In this case, however, the licensee is using up a significant portion of the allowable outage time, i.e one hour to place the channel in trip and 4 hours to reduce power. Another reason is that the benefit to safety derived from meeting surveillance requirements is considered to more than compensate for the risk to safety in having equipment out of service. It does not appear in this case that the licensee has sufficiently weighed the expected improvement in equipment reliability against the potential risk from operating the facility in an LCO action statement. Pending further review and discussion with NRR of the TS intent, this is identified as Unresolved Item 50-338/92-29-01: PRNI Channel Testing in Bypass.

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

   a. (Closed) Violation 50-338, 339/91-10-01, Failure to Implement Procedures with Four Examples

   This violation involved a number of operator errors which were caused primarily due to a lack of attention to detail and failure to employ self-checking techniques. The errors resulted in a loss of an emergency bus, a RCS level system being rendered inoperable, an unplanned ESF actuation and an EDG incorrectly paralleled to the grid during testing. In addition to the cited examples, a declining trend in the area of operator errors was noted by the inspectors. Following the issuance of this violation, two other violations (IRs 50-338/91-26-01 and 50-338/92-03-01) were cited which also were partially attributable to operator error. The two latter violations have been closed by previous inspections.

To address the specific examples cited by this violation, the licensee increased training and awareness in self-check techniques, issued an independent verification operations standard and obtained assistance from an outside organization to evaluate human performance concerns. In addition, and because of the apparent trend, the licensee has aggressively pursued over the last year the causes for the human errors in order to reduce the number. The attention and resources committed to this issue by management has greatly increased the awareness of the operations and plant staff with respect to attention-to-detail and self-check techniques.

The following examples demonstrate some of management's accomplishments that have reduced the error rate since this concern was first raised:

- Revision of the self-check philosophy to make it less complex and more user friendly - The self-check method was reduced from a seven step process to the current four step procedure. Training on self-check methods was provided to the operations staff. Self-check badges, buttons, posters and plaques are routinely worn by individuals and disseminated throughout the plant.

- Extensive QA witnessing and data collection of operator independent verification - The witnessing included tagging and procedural step verifications. Over 39,000 independent verification activities have been witnessed. The data and observations are trended and presented to management. The observations have helped to identify areas which have in the past been shown to be precursors to errors. For example, QA identified on several occasions that operators assigned to perform a tagout or procedure step would be interrupted or otherwise distracted from the task. Management implemented corrective action to address these distractions.

- Aggressive approach toward tracking, trending and reporting of errors - All tagging and procedural performance errors, regardless of significance, are reported per the DR process. Errors are divided into severity levels with the highest level resulting in a TS violation. The error rate and trends are subsequently reported to management.

- An industry-recognized human performance expert has made two site visits to evaluate the methodology for collection of personnel error data and to recommend enhancements for human performance improvement.

- HPES evaluation of errors deemed necessary by management.

- Improvement in procedures as exemplified by the ability to electronically revise procedures and reduce the backlog of PARs.

Overall, the inspectors considered that management initiatives taken as a result of an apparent trend in error rate have had positive results.

b. (Closed) Inspector Followup Item 50-338/92-14-01: Klockner Moeller Breaker Failures

The licensee reported the defective polymer-fiber spring arm in the breaker operating mechanism in accordance with 10 CFR 21 on July 1, 1992. The licensee implemented a compensatory program to visually check for tripped breakers on a daily basis until the breakers were replaced. A replacement program was also developed which prioritized changeout of 83 circuit breakers. To date, all non-outage circuit breakers have been replaced. Six replacements will be done during refueling outages. The replacements were accomplished under strict controls using a procedure specifically developed for the issue. The procedure required bench tests of replacement breakers which included insulation resistance, resistance readings across contacts, short time overcurrent response time tests and instantaneous tests. All replacements were witnessed by QC and key steps were independently verified. In addition, since load testing would not be practical in all cases with the unit operating, all electrical connections were video taped for further verification.

The licensee performed a root cause analysis which determined that the cracks were stress cycle related due to an inadequate design. This conclusion conflicted with a failure report received from the manufacturer which concluded that a chloro-flouro carbon chemical cleanser or lubricant must have been used and contributed to stress corrosion cracking. Since the breakers are molded-case, the licensee performs no such intrusive maintenance.

While the root cause analysis remains inconclusive, the inspectors considered the licensee's corrective actions to be prompt, extensive and carefully coordinated.

8. Exit (30703)

The inspection scope and findings were summarized on December 22, 1992, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results listed below. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Item Number	Description and Reference
50-338/92-29-01	(URI) Power Range Channel Testing in Bypass (para 6.c)

9. Acronyms and Initialisms

AFW	Auxiliary Feedwater
CFR	Code of Federal Regulations
CRO	Control Room Operator
DC	Design Change
DCP	Design Change Package
DR	Deviation Report
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ESF	Engineered Safety Feature
EWR	Engineering Work Request
HPES	Human Performance Evaluation System
IR	Inspection Report
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MOV	Motor-Operated Valve
MW	Megawatt
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
PAR	Procedure Action Request
PM	Preventive Maintenance
PT	Periodic Test
PRNI	Power Range Nuclear Instrument
QA	Quality Assurance
QC	Quality Control
RCM	Reliability-Centered Maintenance
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RTD	Resistance Temperature Detector
SW	Service Water
TS	Technical Specification
UF	Underfrequency
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VPAP	Virginia Power Administrative Procedure
WR	Work Request