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

Report Nos.: 50-338/92-04 and 50-339/92-04

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: February 16, 1992 - March 21, 1992

Inspectors: A. Ruff For M. Lesser 4/16/92
M. S. Lesser, Senior Resident Inspector Date Signed

A. Ruff For D. Taylor
D. R. Taylor, Resident Inspector Date Signed

Accompanying Inspectors: A. B. Ruff
B. C. Haag

Approved by: T. M. Ross 4/16/92
T. M. Ross, Acting Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine inspection by the resident inspectors involved the following areas: operations, maintenance, surveillance, evaluation of licensee self-assessment capability, licensee event report followup, and licensee actions on previous inspection findings.

Results:

In the area of operations, both the Unit 1 startup and Unit 2 shutdown were observed to be deliberate and well controlled evolutions (para 3.a and 5.c).

In the area of operations, a weakness was identified regarding the licensee's failure to adequately ensure all required supporting information is updated when implementing license amendments (para 4.a).

In the area of maintenance/surveillance, the licensee's conduct of the Containment Depressurization Actuation Functional Test and Turbine Overspeed Trip Test were well coordinated and controlled (para 5.a and b).

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In the area of maintenance/surveillance, two violations were identified regarding the licensee's failure to perform adequate surveillance testing on reactor coolant pump undervoltage and underfrequency relays in accordance with Technical Specifications. Prior corrective actions for a previous violation was not thorough enough to prevent reoccurrence. Further corrective action by the licensee has identified a third missed surveillance which is considered an unresolved item (para 5.c).

In the area of safety assessment/quality verification, the licensee's program, and personnel qualifications necessary to perform safety evaluations was found to be acceptable. However, qualifications for personnel to perform activity screening checklists are not clearly defined (para 6.a).

In the area of safety assessment/quality verification, licensee management meetings continue to be a strength in assuring oversight over station programs (para 6.b).

In the area of engineering/technical support, a significant improvement was noted in the areas of procedure writing, specifically Procedure Action Request backlog reduction (para 8.d).

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 Inspectors

*M. Lesser, Senior Resident Inspector
*D. Taylor, Resident Inspector
A. Ruff, Project Engineer
B. Haag, Senior Resident Inspector, V. C. Summer

*Attended exit interview

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

2. Plant Status

Unit 1 - A mid-cycle SG inspection outage was conducted from December 23, 1991 to March 5, 1992. This outage work was originally scheduled to be conducted as part of a 60-day refueling outage beginning in April 1992; however, it became necessary to begin work earlier because of concerns about SG tube integrity. The mid-cycle outage was extended to 72 days due to increased RPC inspection of the SGs. Activities accomplished during the outage included: 100 percent RPC eddy current testing of the hot legs, fuel transfer drive system modifications, pressurizer heater circuit upgrades, station battery I-IV and EDG battery replacements, control room benchboard modifications and SG replacement pre-outage work. The unit returned to service and achieved 95 percent power (maximum power limited due to excessive plugging of SG tubes) on March 9, 1992.

Unit 2 - The unit began the inspection period in a coastdown for refueling. On February 26, the unit was shutdown from 70 percent power for a scheduled 60 day refueling outage. The unit remained in a shutdown condition for the duration 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 DRs were followed to ensure that appropriate management attention and corrective action was applied.

a. Unit 1 - Startup and Reactor Trip

On March 3, Unit 1 entered mode 4. A reactor startup was commenced on March 5. However, while still in mode 3, four group 2 rods in control bank D dropped all the way in (from 80 steps out) following a rod control urgent failure alarm. Operators initiated a manual reactor trip in accordance with 1-AP 1.4, "Dropped Rod." No temperature or pressure transient resulted from the trip. Subsequent rod control system troubleshooting could not positively identify the cause of the rod control failure, but identified two printed circuit cards in power cabinet 2BD as suspect. These were the firing card and the stationary gripper regulator card; both were replaced. Following the card replacements, the unit startup was completed.

The inspectors observed licensee actions during certain phases of plant heatup and witnessed startup of the reactor. The evolution was noted to be deliberate and well controlled.

b. EDG Wiring Deficiency

The inspectors reviewed DR 92-56 which addressed discrepancies between the actual wiring configuration of the 1H EDG control circuitry and applicable controlled drawings. This condition was identified by an I&C technician while installing a modification to the 1H EDG control cabinet 1-EE-EG-01C. The as-found condition resulted in vital bus 1-I being tied into a semi-vital bus through a 15 ampere fuse. The licensee determined that the discrepant condition occurred when a space heater modification was made several years earlier.

The inspectors were concerned about the potential for overloading vital bus 1-I and fault propagation from the semi-vital bus. The licensee conducted an evaluation and determined that the 15 amp fuse limited additional electrical loads to a value that would not have overloaded the 1-I inverter, and would have also prevented a fault in the semi-vital bus from affecting the vital bus. The improper wiring was ultimately corrected to match design drawings, and the remaining EDGs were verified to be wired correctly.

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.

The NRC issued license amendment number 154 for Unit 1, which prescribed changes to TS requirements for reactor protection channels due to increased SG tube plugging. This amendment also added a license condition that limits reactor power level to 95 percent until Unit 1 SGs are replaced. The amended TS changed the K_1 and K_4 constants in the overtemperature and overpower delta T setpoints. It also changed the power range neutron flux high trip setpoint. The inspectors reviewed calculation EE-0416, "Scaling of North Anna 1 Overtemperature Protection Loop," which was performed to implement the K_1 constant change. The inspectors verified that the calibration cardinal points specified in the calculation were properly transferred to instrument calibration procedures. As-left data sheets for delta T/Tave protection channels were reviewed. Additionally, as-left data sheets for reduced power range trip setpoints and overpower rod stops were reviewed and found acceptable.

However, the inspectors determined that some of the applicable supporting documentation was not revised accordingly. The inspectors identified that the annunciator response procedures, as accessed from the Operations Local Area Network Computer, had not been updated to reflect the new trip setpoints for the power range nuclear instruments. The operators typically refer to the computer to respond to annunciator alarms. The inspectors also identified that computer point alarms associated with high reactor power were still based on 100 percent licensed power level. In response to these inspection findings, the licensee updated all applicable supporting procedures and computer point alarms.

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. Unit 2 Shutdown and Turbine Overspeed Trip Test

On February 26, Unit 2 was shutdown for a scheduled refue`'ng outage. The inspectors monitored the shutdown of Unit 2, and after the main generator was removed from service, observed the performance of 2-PT-34.5, "Generator Overspeed Trip Test". This procedure is performed every 18 months to demonstrate the operability of the turbine generator overspeed trip system. The test first verifies the turbine mechanical trip is functioning properly by blocking an actual turbine trip by using the overspeed trip test lever and opening the trip test valves. After confirming mechanical trip is functioning properly, this trip feature is unblocked and turbine speed is manually increased to the trip setpoint.

The procedure called for raising turbine speed to approximately 1962 rpm which is two percent below the trip setpoint and then "bumping" the turbine speed up until the turbine trips. The inspectors noted that the two percent value below the trip setpoint was high enough to be within the trip tolerances (1998, +0 -58 rpm). The operators compensated for this by initially raising turbine speed to below the lower allowable value of the trip and then bumping speed up until the trip occurred. The overspeed trip occurred at 1937 rpm which is 3 rpm below the acceptable value for this trip setpoint. DR 92-545 was initiated to document the unsatisfactory results. The licensee contacted Westinghouse concerning the trip setpoint and assigned maintenance engineering to evaluate the DR for corrective action. The Unit 2 shutdown and turbine trip test were both well coordinated and controlled.

b. Contained Depressurization Actuation Functional Testing

The inspector observed portions of the CDA functional testing conducted by the licensee on March 3, 1992 using 1-PT-66.3. The actual functions observed included isolation of 1A containment trip valves TV-IS-102A and B, 1H stub bus breaker trip, and component cooling pump 1A trip. Testing was well coordinated and particular care was exercised in properly identifying components prior to using jumpers to simulate CDA signals.

c. Reactor Coolant Pump Bus Underfrequency and Undervoltage Relays

On March 6, the inspectors witnessed testing on the RCP bus underfrequency relays. Technicians used procedure 2 PT-33.4B, "RCP Underfrequency Input to SSPS", to perform the channel calibration surveillance on a refueling interval as required by TS Table 4.3-1. The calibration consisted of determining that the trip setpoint and time delay met the appropriate acceptance criteria of 56.5 +/-0.1 Hz and less than 0.11 seconds.

The inspectors noted on the front of each relay panel a test switch, which is used for performing functional tests at power, i.e., the switch simply removes power to one relay at a time to verify that the relay trips. However, the inspectors determined that the licensee does not perform a functional test on these relays nor on the RCP undervoltage relays. TS Table 4.3-1 requires a monthly channel functional test of the RCP bus underfrequency and undervoltage relays for Unit 2. There is no corresponding TS requirement for Unit 1. The licensee's TS surveillance cross-reference list incorrectly listed these surveillances being performed by the bi-monthly SSPS logic PT. This is identified as Violation 50-339/92-04-01: Failure to Perform Monthly Functional Tests on RCP Bus Undervoltage and Underfrequency Relays.

Section 7.2.2.2.1.6 of the UFSAR discusses testing of the reactor protection instrumentation. This testing is divided into two sections: 1) check of input relays, and 2) check of logic matrices. Input relay checking is typically done monthly and involves placing each protection channel bistable in the trip mode, causing the input relay in train A SSPS and train B SSPS to de-energize. Status lamps and annunciators that indicate the input relays have de-energized are then verified. The UFSAR specifically states:

> "Contact inputs to the logic protection system, such as reactor coolant pump bus underfrequency relays, operate input relays, which are tested by operating the remote contacts [placing the sensor in the trip condition] and using the same type of indications as those provided for bistable input relays.
>
> The actuation of the input relays provides the overlap between the testing of the logic protection system and the testing of those systems supplying the inputs to the logic protection system. Test indications are status lamps and annunciators on the control board. Inputs to the logic protection system are checked one channel at a time, leaving the other channels in service. For example, a function that trips the reactor when two out of four channels trip becomes a one-out-of-three trip when one channel is placed in the trip mode. Both trains of the logic protection system remain in service during this portion of the test."

Logic matrices are typically checked every other month and involve semiautomatic testing of all logic coincidences for SSPS train A and B. However, it appears that the licensee's surveillance program has not been checking the input relays of both the RCP bus underfrequency and undervoltage reactor trip channels on both units as described in the UFSAR and required by Unit 2 TS Table 4-3.1.

The TS require undervoltage relay channels to be calibrated at refueling intervals. On March 13, the inspectors questioned the adequacy of the PTs used to perform these surveillances since it did not appear that the entire channel was being calibrated. The licensee's review showed that the refueling PTs for the RCP under-voltage relays failed to encompass the alarm and trip functions, i.e. observing correct response of control room status lights or annunciators. Since the definition of a channel calibration in section 1.3 of TS specifically requires this to assure overlap, the surveillance procedures were inadequate. The licensee reviewed past documentation, including alarm printer records, to confirm that undervoltage testing had actuated the SSPS input relays. But, since no documentation could be found for one of the three channels, that channel was declared inoperable and subsequently tested at power. This is identified as Violation 50-338,339/92-04-02: Inadequate Procedures for Refueling Frequency Undervoltage Relay Surveillance.

The licensee has experienced similar failures to adequately test electrical relays in accordance with TS. LER 91-18, dated September 10, 1991, reported a failure to test emergency bus undervoltage (72 percent) relays in accordance with TS Table 4.3-2 due to incorrectly interpreting the TS surveillance and setpoint requirements. A contributing factor to the event involved the fact that the procedures used to calibrate the undervoltage relays were not part of the licensee's PT program and, therefore, there was no cross reference to alert the user that the acceptance criteria was associated with a TS. This was also the subject of violation 91-17-01. The licensee's corrective action stated "a thorough review of TS Tables which contain relay setpoints was performed to identify other relays with TS setpoint requirements which are not currently verified by periodic tests. Periodic tests will be established for all relays with TS setpoint requirements." Additionally, management discussed the event with involved personnel to emphasize strict compliance with TS.

In the most recent cases involving RCP undervoltage and under-frequency relays (discussed above), the licensee's cross-reference list incorrectly identified the monthly surveillance requirement as being met by the PT associated with the SSPS logic matrix checks. For the refueling PTs, the cross-reference list was correct; however, the PTs were inadequate. The inspectors determined that the licensee's review of the TS tables, performed as the corrective action for a previous violation, merely matched a TS surveillance requirement with a PT number. No attempt was made to assess whether the listed PT adequately accomplished the surveillance. From this respect, it appears that the corrective action was neither thorough nor broadly directed.

The licensee has since initiated a more indepth and comprehensive review of TS required surveillances. During this review, the licensee has identified another missed TS surveillance. Item 19 of TS Table 4.3-1 requires a monthly channel functional test of Safety Injection Input from ESF to Reactor Trip. However, the licensee had been testing this feature every other month. Pending completion of the licensee's review, this will be identified as Unresolved Item 50-338,339/92-04-03: Indepth Review of TS Surveillance Procedures.

Two violations and one UNR were identified.

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

a. Safety Evaluation Training and Qualification

The inspectors reviewed portions of the licensee's program for performing SEs of changes to the plant in accordance with 10 CFR 50.59. The inspectors also reviewed training lesson plans for 50.59 training and qualification requirements for preparers. The licensee's program is described in VPAP 3001, "Safety Evaluations."

The qualifications necessary for preparing safety evaluations are extensive and include specific requirements in education, experience, systems training and 50.59 training. However, the qualifications necessary to perform Activity Screening Checklists (a checklist to determine if a change will need a SE) only require completion of the 50.59 training. The inspectors pointed out that in order to perform effective Activity Screening Checklists some level of education, experience, UFSAR familiarity and systems training is clearly needed. Generally, Activity Screening Checklists are being conducted by personnel familiar with the system or procedure which is being changed and although qualification requirements are not prescribed, they appear to be informally enforced. The inspectors reviewed several Activity Screening Checklists for ICP and PT procedure changes and no problems were identified.

Lesson plan materials were reviewed for adequacy. Previous sessions of SE training lasted two or three hours. The licensee recently revised its lesson plan to include background material and to allow for more extensive discussion of SEs. The most recent training appeared to be of high quality and lasted six hours.

b. Station Oversight Board Meetings

The inspectors attended portions of the SOB meeting on February 26. The meeting included Unit 1 startup assessment following the mid-cycle SG inspection outage. Each department addressed action items needed prior to startup. These meetings are routinely held following an outage and they continue to be a strength in assuring station management oversight for reactor operations.

The inspectors attended the SOB meeting on March 13 and observed station management address several concerns from a management perspective including the following:

-- A reactor trip signal was inadvertently initiated during testing while in mode 5 and resulted in a reportable event. Management focused both on the adequacy of the procedure and the plant conditions for testing.

-- An inadvertent ESF signal caused an instrument air valve to shut during testing due to a sticking relay. It was identified that this type of relay exhibits a history of failing to properly reset. While the safety function of the relay to actuate is not in question, the licensee has apparently been tolerating the defective relays by providing compensatory measures in the form of instructions and training on how to reset the relays. Management focused on the need to explore for a replacement relay.

-- The licensee has identified an adverse trend regarding failing to follow administrative procedures. Contributing to the problem is the extensive upgrade effort for VPAP and the lack of an effective training program to ensure personnel are aware of new or revised requirements.

Open and frank discussions were held on all issues. The meetings are routinely held and represent a programmatic strength in assuring oversight of station problems.

7. LER Followup (92700)

The following LER was 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 50-339/91-10: Condenser Air Ejector Isolation and Subsequent Bypassing of Flow to the Radiation Monitor

The licensee revised procedures 1(2)-OP-30.6, "Secondary Plant Air In-Leakage Inspections," to provide step-by-step instructions for aligning the air ejector system for using portable air in-leakage detection equipment. Placards have been placed near the air ejectors to warn that flow must be through the radiation monitor at all times. These corrective actions were verified by the inspector. This was also the subject of NCV 50-339/91-22-01.

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

   a. (Closed) Inspector Followup Item 50-338/90-30-01: Liquid Effluent Proportional Sampler Unreliability. The licensee performed EWR 90-330 which installed a 3-way solenoid operated valve in the sampling line with one port connected to an air supply. The valve is controlled by a local push button which will supply air to the sampling valve to flush it periodically. Discussions with plant personnel indicate that the reliability of the system has increased significantly. The sampler is now being maintained operable and compensatory grab samples are generally no longer required.

   b. (Closed) Inspector Followup Item 50-338/90-30-02: Safeguard Ventilation Flow Balance and Damper Position Control. Followup of this item is also documented in Inspection Report 50-338, 339/91-26. EWR 90-381A was generated to research the design basis for the safeguards area ventilation system, identify the desired air flow rates from the recirculation spray and safety injection pump cubicles and perform a flow balance test to adjust damper positions. The test was performed on both units. The dampers were properly positioned and caution signs affixed near the damper operators to prevent unauthorized adjustments.

   c. (Closed) Inspector Followup Item 50-338/91-07-01: Establishment of Guidelines for Determining Skill-of-the-Craft Maintenance Activities Not Requiring Written Procedures. The licensee revised VPAP 0801, "Maintenance Program," to provide guidelines for skill-of-the-craft work evolutions. Section 6.3.3 specifies that maintenance on safety related equipment, except for minor maintenance, shall be performed with written procedures or work instructions provided on the work order. If an applicable procedure is available, it shall be used. The level of detail of the procedure or instructions should consider several factors such as complexity, sequence of steps, personnel experience and effect on equipment operability. Skills normally possessed by a qualified maintenance person may not require detailed step-by-step delineations and this decision rests with the Superintendent of Maintenance or designee.

   d. (Closed) Inspector Followup Item 50-338/91-19-01: Excessive EWR Backlog Requiring Procedure Impact Review. The licensee reviewed and eliminated the backlog of implemented EWRs needing impact review. The licensee's program now more appropriately reviews EWRs and DCPs for procedure impact prior to implementation. In the area of procedures writing, the inspectors observed significant improvements in PAR backlog reduction, priority establishment, and quality controls. For example, the I&C PAR backlog had been reduced from 618 in August 1991 to 178 as of March 11, 1992. Pen-and-ink procedure changes for I&C and operations procedures are being phased out with the advent of electronic PARs. This is where PARs are being processed and retyped via a dedicated procedure writer who has access to the computer. Other improvements noted include the writing of a background document on major operations procedures such as those involving reactor shutdown. The document provides the basis for many steps, lessons learned, and appears to be a good method for operators to maintain an integrated perspective during major evolutions. Licensee initiatives in this area represent a strength.

e. (Closed) TI 2500/14, Inspection of the Location of the Manual Trip Circuit in Westinghouse-Designed Plants with a Solid State Protection System. During the review of NRC Information Notice 85-18 for short-circuit failures of output transistors in the UV output circuit board for the Westinghouse SSPS, it was noted that some controlled drawings for this system erroneously showed that the manual trip circuit was located upstream with relation to output transistors Q3 and Q4. To insure that the controlled drawing for this system reflected the proper location of the manual trip circuit, at the various facilities, a verification inspection was made of sites' controlled drawing for this system. The drawing is correct if it shows the manual trip circuit to be downstream with relation to the transistors Q3 and Q4 in the UV output circuit. North Anna's controlled drawing, NA-DW-1082H41 Rev 0, UV Output, Units 1 & 2, Sheet 13 of 29, in Records Management and I & C show the proper location of the manual trip circuit with relation to transistors Q3 and Q4.

f. (Closed) TI 2500/20, Inspection to Determine Compliance with ATWS Rule, 10 CFR 50.62. After a review of the licensee's proposed implementation of the ATWS Rule for North Anna, an NRC SE report was issued for North Anna on May 26, 1988. Following the issuance of the staff's SE report, several inspections have been made in the AMSAC area at North Anna. Two inspections covered most of the items in the TI. One, which covered design engineering, confirmation of completed work, and quality assurance and qualification of the TI, was conducted on May 24 and 25, 1989, by an AMSAC inspection team from SICB of NRR. These areas were acceptable and consistent with the licensee submittal. (See the attached enclosure for a more detailed discussion of this inspection.) The second inspection, which covered procurement and installation, was done as part of a SSOMI inspection during February and March of 1989 and is documented in NRC Inspection Report 50-339/89-200.

The QA guidance for AMSAC equipment that is not safety-related was provided in GL 85-06. The licensee's letter, dated February 18, 1988, gave a detailed response to each of the 18 criteria in the GL with respect to implementation of the QA program at North Anna for this system. Portions of the QA program were examined in previous inspections of the AMSAC equipment. During this inspection, some parts of the completed DCP 87-12-2 were reviewed to verify QA program features, which included the verification of QC Hold points and QC signoffs that were used in the DCP for the AMSAC system installation. During the installation process, nonconformances (i.e., DRs) were identified and corrected in a timely manner. Portions of the receipt inspection reports, associated with the AMSAC equipment covered by

PO BNT-166167, were also reviewed to verify acceptability of receipt inspection and QA program features.

The AMSAC system was operable for Unit 1 in the summer of 1989 and for Unit 2 in the fall of 1990.

10. Exit (30703)

The inspection scope and findings were summarized on April 3, 1992, 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 50-339/92-04-01	Failure to Perform Monthly Functional Tests on RCP Bus Undervoltage and Underfrequency Relays (para 5.c)
VIO 50-338,339/ 92-04-02	Inadequate Procedures for Refueling Frequency RCP Undervoltage Relay Surveillance (para 5.c)
UNR 50-338,339/ 92-04-03	Indepth Review of TS Surveillance Procedures (para 5.c)

11. Acronyms and Initialisms

AMSAC	Anticipated Transient Without Scram Mitigating System Actuation Circuit
ATWS	Anticipated Transient Without Scram
CDA	Containment Depressurization Actuation
CFR	Code of Federal Regulations
DCP	Design Change Package
DR	Deviation Report
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ESF	Engineered Safety Feature
EWR	Engineering Work Request
GL	Generic Letter
IA	Instrument Air
I&C	Instrumentation and Control
ICP	Instrument Calibration Procedure
LCO	Limiting Condition for Operation
LER	Licensee Event Report
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
PAR	Procedure Action Request

PO	Purchase Order
PT	Periodic Test
QA	Quality Assurance
QC	Quality Control
RCP	Reactor Coolant Pump
RPC	Rotating Pancake Coil
RPM	Revolutions Per Minute
SE	Safety Evaluation
SG	Steam Generator
SOB	Station Oversight Board
SICB	Systems Instrumentation and Controls Branch
SSOMI	Safety System Outage Modification Inspection
SSPS	Solid State Protection System
TI	Temporary Instruction
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
UNR	Unresolved Item
UV	Undervoltage
VIO	Violation
VPAP	Virginia Power Administrative Procedure

ATTACHMENT TO THE ENCLOSURE

ATTACHMENT

1.0 INTRODUCTION

The Office of Nuclear Reactor Regulation (NRR) of the Nuclear Regulatory Commission (NRC) assisted by the Idaho National Engineering Laboratory (INEL) conducted a post-implementation inspection of the ATWS Mitigating System Actuation Circuitry (AMSAC) at the North Anna Power Station, Units 1 & 2, on May 24 and 25, 1989.

The purpose of this inspection was to evaluate the Virginia Electric and Power Company (licensee) implementation of the AMSAC design and installation in accordance with the licensee's updated North Anna plant-specific AMSAC design dated February 18, 1988 (Ref. 1) and the NRR/NRC Safety Evaluation Report (SER) addressing the North Anna AMSAC design issued May 26, 1988 (Ref. 2). A secondary purpose of the inspection was to evaluate Temporary Instruction (TI) 2500/20 Revision 1, dated March 24, 1989 (Ref. 3) as a guideline for inspectors performing post-implementaion inspections of the AMSAC design and equipment installation.

2.0 TECHNICAL EVALUATION

2.1 General

At the North Anna Station, the licensee implemented the AMSAC design which is based on steam generator low water level actuation. To reduce the possibility of spurious AMSAC actuations, the AMSAC design incorporates two-out-of-three logic taken twice. The SER issued to the licensee by Reference 2 stated that the staff's acceptance of the North Anna AMSAC design was subject to the completion of certain human-factors engineering reviews to which the licensee had committed. The AMSAC inspection team discussed the human-factors aspects with the licensee and were satisfied by the efforts made by the licensee in this area. This commitment on the part of the licensee has been fulfilled.

Concurrent with the AMSAC inspection team, a Safety System Outage Modification Inspection (SSOMI) team was at the North Anna site inspecting installations of the various modification packages being undertaken by the licensee during the present Unit 1 outage. One of the packages selected for inspection by the SSOMI team was the AMSAC installation package. This package was given a thorough inspection addressing many of the line items contained in TI 2500/20 that dealt with the installation of the AMSAC.

The AMSAC inspection team and the SSOMI team met and discussed the SSOMI team's findings with respect to the physical integration of the AMSAC into the plant (Unit 1). With the exception of some minor discrepancies associated with the AMSAC control cabinet, the SSOMI team felt that the existing safety features of the plant had not been compromised as a result of having installed the AMSAC.

The AMSAC inspection team elected not to duplicate the efforts of the SSOMI team and the SSOMI team's Inspection Report Nos. 50-338/89-200 (Unit 1) and 50-339/89-201 (Unit 2), not attached, provide installation details of the AMSAC. The AMSAC inspection team then concentrated on the design engineering aspects of the AMSAC, the details of which follow.

2.2 Main Control Room

The AMSAC control and alarms located in the main control room (MCR) consist of a control switch and annunciator alarms. The control switch, TAG No. 43-2RPSN05 (Unit2), has "RESET-NORMAL-BYPASS" functions which permit the operators to control the AMSAC for test and maintenance purposes while at power and to reset the AMSAC output devices. The annunciator contained seven (7) AMSAC status point which are:

1. AMSAC - INITIATED
2. AMSAC - MAN - BYP
3. AMSAC - TEST SWITCH - OUT OF NORM

4. AMSAC - OPERATIONAL - BYP
5. AMSAC - ARMED
6. AMSAC - TRBL
7. AMSAC - VIOL - DOOR OPEN

The annunciator points were integrated into the existing MCR annunciator panels and the indicators were designed using the "black board" approach. This approach assumes that the annunciator windows are normally dark and illuminate whenever an abnormal condition occurs.

The plant operating procedures require that any alarm be corrected immediately and the annunciator be returned to the "black board." This procedure ensures that the AMSAC will not go into a trouble or bypass mode and be left there for an extended period of time.

The AMSAC inspection team found the licensee's integration of the AMSAC into the MCR to be acceptable and consistent with the licensee submittals.

2.3 Remote Location

The AMSAC equipment external to the MCR is located in what the licensee terms the Instrument Rack Room (IRR) and consists of an AMSAC control cabinet. This cabinet contains the non-safety related logic equipment, control switches, test points, indicators, meters, relays, and provisions for the interfaces between the non-safety related AMSAC and the safety-related areas of the plant that are associated with the AMSAC. The cabinet was procured and installed as Seismic Class 1, safety grade because it contains safety-related equipment and is in the vicinity of Reactor Protection System (RPS) cabinets.

The AMSAC logic equipment is Gould Series 800 Programmable Logic Controllers (PLCs). The PLCs are not used anywhere in the RPS and are powered by a non-safety related uninterruptable power supply (UPS). In addition to the UPS, the software has its own backup battery. The PLCs and their associated power supplies are key locked with the keys under the administrative control of the control room operator. This method helps to ensure the integrity of the software which is under the control of the licensee's engineering department. The AMSAC inspection team noted that the AMSAC was designed such that it is capable of being tested and calibrated without having to lift leads, apply shorts, block relays or resort to any undesirable method for testing.

Safety Division 1 - Orange and Safety Division 2 - Purple enter the AMSAC cabinet from the top of the cabinet and are separated from each other and from the non-safety section of the cabinet by steel plates. The two safety divisions enter the non-safety section of the cabinet via safety related isolation relays (Electro Switch Model 24 CSR rotary relays). These relays are not used within the RPS. The input signals to the AMSAC cabinet come from existing RPS cabinets located in the IRR. The signals are isolated by Westinghouse 7300 System isolators.

The AMSAC inspection team found the licensee's integration of the AMSAC cabinet into the IRR to be acceptable and consistent with the licensee submittals.

2.3 Procedures

The AMSAC inspection team was able to determine that the licensee had procedures in place and working or in the preparation stage that addressed the AMSAC with respect to:

1. Quality Assurance (QA)
2. Testing
3. Training
4. Operation
5. Emergencies
6. Maintenance

The QA procedures, operating procedures, and emergency operating procedures were updated to include the AMSAC. New testing, training, and maintenance procedures were written for the AMSAC. Being a new system, the AMSAC inspection team focussed on the training of licensee personnel with respect to the AMSAC. The licensee stated that 80 percent of the technical staff had been trained in the AMSAC. The licensee developed a training course for the control room operators which will be presented on a recurring basis. The AMSAC vendor is scheduled to visit the North Anna site in July of this year to teach and train the staff in the use and maintenance of the equipment. It is the licensee's intent to develop a training course patterned after the vendor course. Also, the plant simulator will be modified to include the AMSAC controls.

The AMSAC inspection team found the licensee's efforts in this area to be acceptable.

2.4 AMSAC Setpoints and Accuracies

The AMSAC inspection team reviewed Calculation No. 14938.46-C-2 which describes in detail the numerical value of the AMSAC setpoints and their associated accuracies. The setpoints as calculated are in agreement with WCAP-10858P-1, Rev. 1, "AMSAC Generic Design Package," dated July 1987 which provides the basis for the setpoints. The AMSAC setpoints and their values are:

1. Steam Generator Narrow Range Low-Low Level: 13% ± 0.26%
2. Turbine First Stage Pressure: 38% ± 1.0%
3. AMSAC Logic Timers
   a) Trip Timer: 27 Sec + 0.25, -1.0 Sec
   b) C-20 Timer: 360 Sec ± 2.0 Sec

The AMSAC inspection team found the setpoints and accuracies to be acceptable.

2.5 Temporary Instruction 2500/20 Revision 1

As stated earlier, TI 2500/20 Revision 1 was used as a guideline in conducting the inspection. That portion of the AMSAC inspection performed by the SSOMI team was consistent with the TI. The SSOMI team completed Section 4.04 "Procurement and Installation of the ATWS Mitigating Equipment."

The AMSAC inspection team covered the following Sections of the TI: Sections 4.03 "Design Engineering," 4.05 "Confirmation of Completed Work," and Section 4.06 "Quality Assurance and Qualifications." The AMSAC team found Section 4.03 Items a and b to be too general and essentially covered by Section 4.04 and 4.05. Section 4.04 (item a, b, g and h) and Section 4.06 are the subjects of inspections and audits by QA assessment teams. The AMSAC team did not delve very deeply into the licensee's QA programs, but the team did ascertain that QA and testing procedures were were in place and that the licensee's technical staff was trained in the operation and maintenance of the AMSAC.

The AMSAC inspection team found the TI to be acceptable for use as a guideline.

3.0 LICENSEE PERSONNEL CONTACTED

Personnel	Function
B. S. Dunlap	Project Engineer
R. O. Enfinger	Ass't Station Manager
J. H. Leberstein	Engineer
S. C. Harvey	Supvr. of ADOPS
D. E. Schappell	NSS Const. Supt.
Jim Lenchalis	Training
David Grubbs	Engineer
Lyn Russell	Training
Russ Anderson	

4.0 REFERENCES

1. Letter, W. L. Stewart (VEPCO) to U.S. NRC, "Virginia Electric and Power Company - North Anna Power Station Units 1 and 2 - Surry Power Station Units 1 and 2 - Anticipated Transient Without Scram - AMSAC Design," February 18, 1988.

2. Letter, L. B. Engle (NRC) to D. S. Cruden (VEPCO), "Compliance with ATWS Rule, 10 CFR 50.62, Surry Power Plant, Units No. 1 and No. 2 (Surry 1&2) and North Anna Power Station, Units No. 1 and No. 2 (NA-1&2) (TAC NOS. 59147, 59148, 59117 and 59118)," May 26, 1988.

3. Temporary Instruction 2500/20, Revision 1, "Inspection to Determine Compliance with ATWS Rule, 10 CFR 50.62," March 24, 1989.