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

Report Nos.: 50-280/92-04 and 50-281/92-04

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

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

Facility Name: Surry 1 and 2

Inspection Conducted: February 2 through March 7, 1992

Inspectors: A Ruff for
M. W. Branch, Senior Resident Inspector 3/26/92
Date Signed

A Ruff for
J. W. York, Resident Inspector 3/26/92
Date Signed

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Approved by:
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Division of Reactor Projects Date Signed

SUMMARY

Scope:

This routine resident inspection was conducted on site in the areas of operations, maintenance, surveillance, quality verification and safety assessment review, independent plant evaluation, and licensee event review. During the performance of this inspection, the resident inspectors conducted reviews of the licensee's backshift or weekend operations on February 2, 13, 16, 17, 19, 23, March 1, 3, 4, and 5, 1992.

Results:

In the operations area, the following items were noted:

. A weakness was identified in that, procedures do not recognize the manual mode of operation of the ventilation system (paragraph 3.a).

. The ability to trend hours spent in action statements will significantly enhance the licensee's ability to focus on problem areas (paragraph 3.e).

. Housekeeping throughout the plant is generally good (paragraph 3.c).

In the maintenance/surveillance area, the following items were noted:

- Planning and implementation of the switchyard CT replacement (paragraph 3.b) demonstrated the following:
  - Coordination of many parallel and series activities as well as the regulatory awareness was observed as a strength.
  - The switchyard design does not allow for normal preventive and corrective maintenance of some switchyard equipment.
- The failure to provide adequate procedures to calibrate the station blackout motor driven AFW pump start relays and to test the T average port of the ESF logic circuits are non-cited licensee identified violations (paragraphs 10.a and b).
- The ESF logic testing observed was well coordinated and received a high level of management attention as evidenced by assignment of the Senior Operations Manager to this infrequent task (paragraph 4.b).

In the SA/QV area, the following items were noted:

- The TS and FSAR failure to describe the ventilation systems manual mode of operation was identified as a weakness (paragraph 8).
- The corporate IR, IOER, and CNS assessment and event review programs were found to be effective and met TS requirements (paragraph 6).
- The failure to properly correct HHSI pump lube oil temperature control valve deficiencies is identified as a violation and weakness (paragraph 3.g).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*W. Benthall, Supervisor, Licensing
*R. Bilyeu, Licensing Engineer
H. H. Blake, Nuclear Safety
*D. Christian, Assistant Station Manager
J. Downs, Superintendent of Outage and Planning
*A. Fletcher, Assistant Superintendent of Engineering
*R. Gwaltney, Superintendent of Maintenance
*D. Hart, Supervisor, Quality Assurance
M. Kansler, Station Manager
*J. McCarthy, Superintendent of Operations
*K. Moore, Vice President-Nuclear Engineering Services
*A. Price, Assistant Station Manager
*R. F. Saunders, Assistant Vice President-Nuclear
*S. Semmes, Senior Staff Engineer
*E. Smith, Site Quality Assurance Manager
T. Sowers, Superintendent of Engineering

NRC Personnel

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

* Attended exit interview.

Other licensee employees contacted included control room operators, shift technical advisors, shift supervisors and other plant personnel.

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

2. Plant Status

Unit 1 began the reporting period at 97 percent power. On January 30, 1992, coastdown began and on February 29, the unit was shutdown from 73 percent power to begin a scheduled 64-day refueling outage.

Unit 2 began the reporting period in power operation. The unit was at power at the end of the inspection period, day 80 of continuous operation.

3. Operational Safety Verification (71707,42700,37828)

The inspectors conducted frequent tours of 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 operations 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 indication 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.

a. Operation Of The Ventilation System

The inspectors reviewed the various operational modes for the emergency ventilation system. When both units are operating at power, the ventilation system will automatically realign when an SI signal occurs in either unit. When the ventilation system realigns, the areas that contain ECCS pumps are exhausted through filters to remove fission products and provide cooling for pump motors. In addition, ventilation to the non-ECCS areas is secured, and ventilation is provided for the operating charging pump in the other unit. When one unit is operating and the other unit is moving fuel, the ventilation system is aligned such that the primary objective is to ensure that the fuel building and containment exhaust is discharged through filters.

In the ventilation system's refueling mode alignment, if an SI signal occurred in the operating unit, the ventilation system would not automatically realign to the SI mode of operation. It would remain in the refueling configuration. Operators would be required to place the fuel in a safe condition and then manually realign the ventilation system for the SI mode of operation. Step 18 of EP 1-E-0, Reactor Trip or Safety Injection, dated January 16, 1992, provides instructions for realignment of the ventilation system when in the refueling mode of operation. Operators estimated that it would take approximately five minutes to place the fuel in a safe condition and realign the ventilation system if required. The ventilation system can be realigned from the control room.

The inspectors reviewed DC 78-S34, Auxilary Ventilation System, dated April 27, 1979. This DC was implemented in 1980 and significantly modified the ventilation system. One of the ventilation system changes implemented by DC 78-S34, added the need to manually realign the system as previously discussed. Prior to 1980, the ventilation system would automatically realign on receipt of an SI signal during the movement of fuel in the other unit. The safety analysis performed for DC 78-S34 recognized this change of operation and considered it acceptable. The safety evaluation, dated January 17, 1984, performed by the NRC staff for amendments 91 and 92 to the operating license, approved this method of operation. The licensee stated that the offsite dose during a refueling accident was significantly higher if the ventilation system exhaust was not filtered; however, not filtering the exhaust from ECCS areas during the first twenty minutes following a LOCA had only a minor effect on the off-site dose.

The inspectors reviewed section 3.22 of the TS and FSAR chapters 5.3 and 9.13 in order determine if the ventilation system was required to realign automatically or manually upon receipt of an SI signal during the movement of fuel. The FSAR only discussed the automatic features of the system and did not describe the need to manually realign the ventilation system in the event of an SI signal in one unit when moving fuel in the other unit. The TS did not state that the system was required to be automatic, but the basis section did describe the system as automatic. The TS and FSAR failure to describe the ventilation systems manual mode of operation was identified as a weakness.

The inspectors noted another example where the emergency ventilation system was aligned such that manual action was required if the system was required to respond to an SI. During this inspection period, operators placed the controllers for the emergency ventilation fans from automatic to manual. In this alignment, operators would have to make ventilation system flow rate adjustments during an SI where normally the flow rate is automatically adjusted. Also, this alignment increases the potential for a fan to trip due to excessive flow rates. Procedures do not recognize this alternate mode of operation. This is considered a weakness because procedures should alert the operators that additional precautions are invoked when in this configuration.

b. Operational Activity Associated With The Replacement of Switchyard Bus #5 Current Transformer.

On February 28, the licensee replaced a current transformer on one of the three phases of bus #5. This activity involved several TS action statements and was closely observed by the inspectors. Switchyard bus #5 supplies power to 2 of the 3 RSSTs, A and B. The A RSST provides off-site power to emergency bus 1-J and the B RSST provides off-site power to the 2-H emergency bus.

The CT which provides protective and metering functions for the 34.5kva/120 vac was noted as having a low fluid level and was leaking fluid. The licensee postulated that failure was eminent. Failure would cause an unplanned loss of 2 of the 3 RSSTs which has in the past resulted in turbine runbacks due to IRPI power spikes. Also, the failure would affect both units and challenge the fast start of 2 of the 3 EDGs. Several TS action statements impact taking the CT and bus #5 out-of-service:

- TS 3.9 "Station Services Systems" requires that the 4160 emergency buses to be energized as explained in TS 3.16

- TS 3.16 "Emergency Power System" requires two EDG to be operable, two emergency buses energized, and two independent offsite circuits to energize the 4160v buses. TS 3.16.B.2 allows the primary source of offsite power to be unavailable for up to seven days as long as back-feed capability exists.

- TS 3.16.B requires that the EDGs be operable when offsite power is degraded (i.e. 3.16.B only allows 3.16.B.1 or 3.16.B.2).

- TS 3.0.2, "Limiting Conditions For Operation" specifies that if the emergency power supply for equipment on one train is inoperable that the normal and backup power supplies for the other equipment must be operable.

The licensee decided to replace the defective CT prior to Unit 1 shutdown with both units at power with the 1J and 2H emergency buses being powered by the #3 and #2 EDGs. Leaving Unit 1 on line allows for emergency backup power by backfeeding the emergency buses if necessary from the station service transformers. During the 6-8 hour time that bus #5 would be unavailable, primary offsite power and EDG alignment would be as follows:

RSST A would be deenergized.
RSST B would be deenergized.
RSST C would be energized.

EDG#3 will be in standby for the 1H bus.
EDG#2 will be running and supplying power to the 2H bus.
EDG#3 will be running and supplying power to the 1J bus.

EDG#3 is the swing EDG and would not be 100 percent operable to supply the Unit 2J bus in an emergency. It would swap to the 2J bus on an ESF signal, but would not on degraded or under voltage conditions.

The above offsite power alignment and EDG availability for the 2J bus would result in violation of TS 3.16.B and, therefore, TS 3.0.1 or 3.0.2 would apply. To replace the CT with both units at power would require entry into TS 3.0.1 if it could be accomplished within the time allowed by TS 3.0.1. However, the licensee determined that based on their estimates the repair would take longer then allowed by TS 3.0.1 and would require a waiver of compliance.

On February 28, at 1236, TS 3.0.1 LCO was entered and the repairs to switchyard bus #5 began. The inspectors monitored the establishment of the required electrical alignment, briefing of the shifts, and starting of and operational parameters for the #2 and #3 EDG's. The licensee used temporary maintenance operating procedure No. TMOP-312, Removal From Service of 34.5 KV Bus #5, dated March 2, 1992. The inspectors made several trips to the switchyard and verified that switchyard access was under control of the security department and that bus #6 had access restricted by barriers. The inspectors observed the removal and replacement of the defective CT and the inspection of the other two CTs which were found to be acceptable.

The inspectors also monitored the restoration of the plants electrical systems after replacement of the CT. The actual time spent in the action of TS 3.0.1 was such that the waiver of compliance was not needed. However, the provisions in the licensee's written request for TS waiver, dated February 28, were verified by the inspectors. The NRC acknowledged the waiver request in a March 2 letter from the Region II Regional Administrator to the Senior Vice-President, Nuclear. The NRC recognized the licensee's extensive planning and regulatory awareness as contributors in reducing the time for repairs such that the requested waiver was not actually needed.

c. Housekeeping

Housekeeping throughout the plant is generally good. The licensee has significantly improved housekeeping in the condensate polishing building, boric acid flats, Unit 1 charging pumps cubicles, cable faults, emergency switchgear room, turbine building, and auxiliary building by refinishing the floors and/or repainting wall and component surfaces. The licensee is in the process of repainting the No. 1 EDG room and Unit 2 charging pump cubicles. Prior to repainting, the original surfaces were sanded or chipped away which sometimes resulted in poor housekeeping in the adjacent areas. Station management has reemphasized the need to maintain good housekeeping to station personnel while painting or other maintenance is in process.

d. Operations TPUP Review

The TPUP program has completed approximately 1162 of the 3700 procedures requiring upgrade in the operations area. The number of completed procedures exceeded the program goals. This program is closely monitored by management and reports are routinely issued in order to inform management of program completion status. The inspectors routinely monitor the performance of upgraded procedures and consider them to be of good quality. The licensee utilized QA assessments and quarterly procedure upgrade surveys to evaluate the effectiveness of this program. Approximately 100 randomly picked procedure users are surveyed quarterly in order to track the stations perception of new procedures. The results of these surveys are utilized to further enhance the quality of procedures.

Vendor manuals are being updated in accordance with the Configuration Management Program. The inspectors were informed that procedures are being upgraded prior to updating vendor manuals and that any vendor manual update that effected procedures would have to be incorporated into procedures at a later date.

e. Computer Programs

The Operations department has implemented a new computer program, VPASS, which aid operators in performing their duties and also records and trends hours spent in TS action statements. Whenever a TS action statement is entered, operators are required to enter the appropriate data into VPASS. At shift turnovers, operators are able to print out all TS action statements for review. Also, the VPASS record of action statements is provided to station management for review. The program is able to sort and trend action statements in many different ways, and provide valuable historical information relative to action statements. For example, the licensee is able to accurately specify how many hours were spent in TS action statements in 1991 due to inoperable charging pumps or any other component or system covered by the TS. The ability to trend hours spent in action statements will significantly enhance the licensee's ability to focus on problem areas.

f. HHSI Pump Lube Oil Cooler TCVs

Each of the six HHSI pumps has a lube oil cooler. Service water is aligned to each cooler to remove heat from the lube oil. As the lube oil temperature increases, a TCV automatically opens and regulate SW flow through the cooler. Review of 1990 and 1991 station deviations revealed that failure of TCVs to automatically control lube oil temperature in the required band was a reoccurring problem. The primary failure mechanisms were the TCV being stuck in the shut or intermediate position due to debris from the SW system that accumulated in the valve internals or the temperature controller not maintaining the proper setpoint. In order to correct these TCV deficiencies, the licensee has replaced TCV disks with disks that are different in material and design on five of the six HHSI pumps and initiated routine flushes to remove silt and other debris from the SW system. The new TCV disks were installed in June, 1990 on all three Unit 1 HHSI pumps and the Unit 2A HHSI pump and in July 1991, on the Unit 2C HHSI pump. This modification has not been performed on the Unit 2B HHSI pump. On August 26, 1991, the licensee began to routinely flush the valves on a two-week interval.

The licensee's corrective actions have reduced TCV failure rates, but the problem continues to exist. On September 10, 1991, the TCV on the Unit 1B HHSI pump failed to properly operate. On November 10 and

December 3, 1991 and on March 2, 1992, the TCV on the Unit 2B HHSI failed to properly operate. On March 6, 1992, the TCV on the Unit 2A HHSI pump failed to properly operate. When these failures occurred, operator manual action or maintenance was required to correct the problem. The licensee is aware that the corrective actions implemented have not eliminated this problem and was in the process of procuring redesigned TCVs and controllers. The materials and procedures required to accomplish this modification are scheduled to be available May 1, 1992. Installation of these new components has not been scheduled. The modification does not require an outage and therefore could be started when materials and procedures are available. The inspectors concluded that until the proposed modification is installed, the licensee needs to implement additional temporary corrective measures to preclude repetitive TCV failures .

HHSI pumps are required to automatically start and operate on receipt of an SI signal. By design, operator manual actions are not required for pump operation during the initial phases of a LOCA. In addition, during the LOCA RMT phase, high radiation levels in the area of the HHSI pumps would prohibit operators from manipulating the TCV controllers. The inspectors are concerned that if a TCV failed to properly control lube oil temperature during a LOCA, significant HHSI pump degradation or failure would occur.

The failure to implement adequate corrective actions to prevent repetitive TCV failures was identified as Violation 280,281/92-04-01.

Within the areas inspected, one violation was identified.

4. Maintenance Inspections (62703, 42700, 71500)

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

The following maintenance activities were reviewed.

a. Roofing Leaks

One of the areas examined during the last inspection period involved the number of roofing leaks present at the Surry plant. During this inspection period, a meeting was held with the manager of Civil/Mechanical Engineering to discuss the roof program. There were several parts to this program; and one part, the auxiliary building roof replacement, has had the specifications established and the roof designed. The total roofing program will be prioritized with the auxiliary building roof being first. The presentation of the roof management program recommendations to upper management is scheduled for March 31, 1992. These recommendations will include repair, replacement, and retrofit for a five-year period. The inspectors will continue to follow this program and its effect on decreasing the number of leaks.

b. Maintenance Program Innovations

The inspectors observed several maintenance innovations that are being implemented to improve the overall performance of the maintenance department. These innovations are as follows:

- During a maintenance self assessment, it was determined that there was a lack of communication between the maintenance manager and the maintenance craftsmen. The maintenance manager decided to alleviate this situation by holding quarterly meetings starting February 1992. The inspectors attended one of these meetings and noted that there was a good exchange of information.

- The maintenance department has started issuing a maintenance department report on a monthly basis. It's purposes are to explain various department tasks and processes, to make individuals more cognizant of their own and other departments' work. Inputs to the December, 1991 report are from electrical maintenance, mechanical maintenance, maintenance engineering, preventive maintenance, MOV, predictive analysis, and welding groups. These articles included such topics as ALARA update on exposure reduction, challenges identified by the maintenance self assessment, EDG task team report, and malfunction of a control rod that caused a manual trip.

- Another innovation involved the meeting of individual maintenance teams with the QMT/ALARA coordinator and some of the managers to establish goals that will improve quality of work and reduce the radiation exposure.

The inspectors will monitor the effect of these innovations with respect to the effects on the quality of maintenance.

c. Feedwater Regulation Valve Repair

During the last two inspection periods, the inspectors have followed the repair of FRVs. In the December period, these valves may have contributed to a turbine/reactor trip caused by a high feedwater level in the B steam generator. A review was made of the licensee's evaluation of the FRV oscillation, including testing and modification documentation. Modification documents and current evaluation showed that a smaller size tubing had been installed for the supply air lines. This smaller tubing size could cause a longer stroke time for the valves.

A station deviation (No. S-92--0121) was written. The licensee reviewed the time for the closing of the valves by reviewing a previous trip/ESF actuation and noted that it took seven seconds to close the valves. Analysis assumptions were for no more than a 10 to

15 second closing time. The licensee is replacing the Unit 1 tubing with the proper size during this outage and the valves will be placed in an ISI program that will provide periodic timing testing of the valves.

Within the areas inspected, no violations were identified.

5. Surveillance Inspections (61726, 42700)

During the reporting period, the inspectors reviewed surveillance activities to assure compliance with the appropriate procedure and TS requirements.

The following surveillance activity was reviewed:

a. Testing of Unit 1 and 2 Relays

During a review of TS change no. 235, the licensee discovered that a relay in the SI system logic sequence was not adequately tested as an active component. The subject relay actuates on low Tave and makes up the matrix needed for high steam flow in coincidence with low Tave or low steam line pressure. The monthly periodic test checks continuity but does not test for relay actuation at the SI contacts. The licensee entered a six hour clock to hot shutdown (TS 3.7 table 3.7-2) at 1413 on February 14. The appropriate perodic tests, 1-PT-8.3A (dated June 27, 1989) and 2-PT-8.3A (dated October 2, 1990), Safety Injection and Feedwater Control Isolation Logic, were revised to include the testing for these relays. The inspectors observed this testing in the ESGR room for both units and reviewed the documentation. Both units were successfully tested and the six hour clock was exited at 1434 hours. An LER (no. S1-92-003) was written to cover this event and is discussed further in paragraph 10.b.

b. 1J Bus ESF Actuation with Undervoltage and Degraded Voltage

The inspectors witnessed the testing of ESF actuation with undervoltage on the 1J bus. The test was accomplished in accordance with procedure 1-OPT-ZZ-002, ESF Actuation With Undervoltage and Degraded Voltage - 1J Bus, dated February 27, 1992. The inspectors reviewed the test instructions and attended the pre-evolution briefing. The licensee had assigned a Senior Operation Manager on duty during performance of this infrequently performed task. This provided the shift crews with the needed support as well as allowing the managers to participate in the briefing and monitor the performance.

Within the areas inspected, no violations were identified.

6. Quality Verification and Safety Assessment Review (40500)

The inspectors conducted a review of the licensee's corporate independent review functions and industry operating experience program. TS 6.1.C.2 requires that the MSRC be responsible for the review of safety evaluations, unreviewed safety questions, TS changes, violations, significant abnormalities, LERs, deficiencies that could affect nuclear safety, and SNSOC meeting minutes. the licensee implemented the requirements by submitting all LERs, violations and TS changes to MSRC members for review.

Additionally, all safety evaluations are independently reviewed by CNS while performing as a subcommittee to the MSRC. CNS also reports to the Manager of Nuclear Licensing and Programs when conducting independent assessments of station activities and when implementing the industry operating experience program. The inspectors reviewed the following program implementing procedures: LICP-4000 Corporate Nuclear Safety, LICP-2001 Independent Review Program, NLP ADM 4.1 Review and Processing of Industry Operating Experience Documents and VPAP 3002 Operating Experience Program.

a. Independent Review Process

Through the Independent Review program, CNS independently reviews all safety evaluations performed in accordance with 10CFR50.59 and reviews all SNSOC meeting minutes. The inspectors discussed the program with responsible personnel, reviewed selected independent verification packages for effectiveness and reviewed qualifications of individuals. Personnel assigned to perform the reviews appeared to collectively possess experience and competence in the diverse disciplines necessary to be effective. However, the training folders for the persons assigned the IR function were not always complete and were difficult to audit.

The inspectors questioned the licensee on the use of the IR process to meet the MSRC oversight requirements of TS 6.1.C.2 since the TS did not specifically discuss the use of subcommittees. The licensee's TS amendment that invoked the current MSRC oversight does discuss the use of subcommittees in the support information and the use of subcommittees is described in the NRC's guidance on oversight of offsite committees. The inspector found the licensee process acceptable and in compliance with TSs. The IR program was clearly defined by the controlling procedure and appeared to be effective in identifying and resolving concerns as well as tracking and reporting the status of items. The inspectors noted that while safety evaluations were reviewed, the licensee's program had no requirements to independently review a sample of activity screening checklists. Improper use of screening checklists could result in not performing the necessary written safety evaluation. Additionally, the person assigned the primary review function for the SNSOC meeting minutes does not attend the meetings. The licensee agreed to consider the need to have the reviewer periodically attend SNSOC meetings and to continue with their assessment of the quality of the safety evaluation screening process.

b. Industry Operating Experience Review

CNS is responsible for maintaining the licensee's IOER Program with the purpose of reviewing IOER documents to assess applicability and develop action plans necessary to prevent or minimize the consequences of previously experienced industry events. IOER documents include NRC Information Notices, Generic Letters, Virginia Power LERs, 10 CFR 21 Notifications, INPO event reports and Westinghouse Technical Bulletins. IOER documents are initially screened within 10 days and assigned a priority to prepare an analysis report and develop all action plan within 30, 60, or 90 days to address the concern. The inspectors selected a sampling of documents and determined that appropriate priority had been assigned and that action plans were of high quality, clearly identifying the concerns and needs for further action. IOERs selected for review included IN 91-46, GL 91-05, IN 88-60, and GL 90-05. The inspectors identified weaknesses with the licensee's tracking system for documents. In many cases, due dates were not assigned, due dates had been exceeded or proposed actions had been rejected with no indication that followup was being pursued. The inspectors determined that in general the actions were being adequately pursued and the problems were confined to maintenance of the tracking system data base.

c. CNS Assessments and Event Reviews

The CNS assessment and event review process is controlled by procedure LICP-4000, Procedure for Performing Assessments and Event Reviews. At the time of the inspection, this procedure was in the concurrence cycle for approval. The new procedure replaced procedure NL&P-ADM-2.2 and incorporated changes in the program and organization. The assessment and event review process is not required by the TS. The stated purpose of the CNS event review and assessment process is to independently evaluate technical issues, performance problems or other areas as requested by the MSRC, senior management, or station management and make recommendations for improvements.

The inspectors discussed the assessment and review process with the supervisor of nuclear safety review and several members of his staff. The planned CNS assessments are integrated with other review activities scheduled at the station. In some cases, personnel from other organizations are included as part of the team. The list of 1991 assessments and reviews were discussed and management's involvement in the process was evident by the number of senior management requested assessments that were performed.

Within the areas inspected, no violations were identified.

7. IPE Internal Flooding Corrective Action Review (71500)

Surry Power Station's IPE determined that it had a higher than expected degree of vulnerability for turbine building flooding. A team inspection was made in November, 1991, to assess the licensee's corrective action plans and interim protective measures. The Chairman held a public meeting on this subject at the Surry Nuclear Information Center on November 29, 1991. Certain actions were taken to reduce this vulnerability, among them was inspection of one of the main condenser outlet expansion joints by the licensee. This was done in order to estimate the service life of the eight affected expansion joints. The inspection showed degradation of this expansion joint and the licensee decided to inspect the remaining expansion joints. There were varying degrees of degradation found in these remaining joints. Consequently, the licensee decided to replace all of these 96 inch diameter expansion joints and committed to accomplish this by February 28. On February 22, this task was completed. Each expansion joint replacement took about ten days and initially the licensee believed that TS waivers would be required for four of these replacements (2 for each unit) because emergency service water lines would have to be isolated by stop log installation. However, the licensee developed and designed a system that did not compromise safety, gave two barriers for worker safety, and eliminated the need to isolate a safety system train thereby negating the need for an TS waivers.

Within the areas inspected, no violations were identified.

8. ESF Verification (71710)

The inspectors walked down the safety related portions of the ventilation system. The ventilation system is shared between the units. Sheets 1, 2, and 3 of drawing 11448-FB-6D were utilized for this walkdown. The following discrepancies were identified during the walkdown:

- Overall labeling of ventilation system components was poor. Manual dampers were not labeled, many had the identification numbers and open/closed positions annotated in handwriting with a felt marker on the component. The handwheel on the motor operated dampers to the charging pump motors were not labeled. Other components were labeled with red tape, duct tape, pencil, or felt marker. The inspectors walked this system down with the Configuration Management labeling personnel, and were informed that the relabeling program which is scheduled for completion in March, 1993 would resolve these deficiencies.

- Oil was dripping from 1-MOD-VS-100B hydraulic actuator. There was oil on the piping and wall below the MOD. The inspectors noted that a work order to repair the oil leak was initiated in February 1990, but was classified as low priority and had not been scheduled to be worked. 1-MOD-VS-100B is required to automatically operate on an SI signal. The inspectors were informed that monthly periodic testing on the ventilation system verifies that the MOD repositions. The inspectors were also informed that if the oil level in the damper's reservoir got too low, the MOD would not open as required. The MOD oil leak has been scheduled to be repaired during the second week of March, 1992.

The inspectors noted that the physical condition of the ventilation system was in the process of being improved. Some of the duct work was recently painted or primed, but the majority of the duct work still needed painting. Housekeeping in the ventilation system areas was adequate.

Within the areas inspected, no violations were identified.

9. Technical Procedures Upgrade Program (42700)

The inspectors discussed the technical procedure upgrade program with the licensee on March 3 and 5. This program was started December 31, 1989, and is scheduled to be completed by December 1996. The following table shows the disciplines and the number of technical procedure that are to be written over the life of the program.

Discipline	Number of Procedures
Electrical	1072
Mechanical	585
I&C	1538
*Ops (Dual)	1915
**Ops (Single)	1784
***Other	588

*Annunciator Procedures and EOPs
**Normal OPS Procedures
***Special Tests, etc.

A review of the status of the TPUP revealed that most of the procedure disciplines are above or just slightly below the goal with the exception of the I&C procedures. The procedures group exceeded the 1991 yearly goal for writing I&C procedures, but still continues to be below the overall goal, i.e. 210 procedures completed and the goal was approximately 410 completions.

The inspectors also reviewed the backlog of PAR's that are used to change or modify the procedures. The PAR program was started in February 1990. Actual procedure revisions would be made when SNSOC directed the procedures group to make the change. In July 1990, this committee directed the procedures group to incorporate changes to procedures when the number of PAR's reached five or more and on February 10, 1992, the process of incorporation of all PAR's into procedures was included in VPAP 0502. As of December 1991, the number of outstanding PARS was 1323 and this appears excessive to the inspectors. Also as of this date there were 23 procedures outstanding that had five or more PARS's and 339 PARS's outstanding that were written in 1990 (161 of these PARS's were for the I&C procedures). Approximately 15 percent of the upgraded procedures have one or more (open or closed) PAR's and approximately 31 percent of the non-upgraded procedures have one or more. This indicates that the upgraded procedures are of better quality and require fewer changes within the areas inspected.

No violations were identified.

10. Licensee Event Review (92700)

The inspectors reviewed the LER's listed below and evaluated the adequacy of corrective action. The inspector's review also included followup on the licensee's implementation of corrective action.

a. (Closed) LER 280,281/92-002, 4160 Volt Transfer Bus D, E, and F Undervoltage Relay Trip Setpoints Set Below TS Limit Due to Procedure Error. This issue involved not setting the station blackout motor driven AFW pump start relays in accordance with the values specified in TSs. This issue and corrective actions were discussed in Inspection Report 280,281/92-02. This event was caused by an error in calibration procedures in that an incorrect UV relay trip setpoint was specified. TS 6.4.A.2 requires detailed written procedures for calibration of components involving nuclear safety of the station. The failure to provide an adequate procedure to calibrate the station blackout motor driven AFW pump start relays is identified as NCV 280,281/92-04-02. This violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section V.G. of the Enforcement Policy.

b. (Closed) LER 280,281/92-003, Incomplete Engineered Safety Features Testing Due to Procedure Deficiency. This issue involved the failure to fully test certain ESF system logic actuation relays in accordance with TS Table 4.1-1, Item 26. Specifically, actuation of the relays which energize on low reactor coolant average temperature were not being verified (see paragraph 5.a for more details). The licensee discovered this during a procedure upgrade. TS 6.4.A.2 requires detailed written procedures for calibration of components involving nuclear safety of the station. The procedures were revised and the relays were tested. This failure to provide an adequate procedure to fully test the ESF system logic actuation relays is identified as NCV 280,281/92-04-03. This violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section V.G. of the Enforcement Policy.

c. (Closed) LER 280/91-13, MCC Room Fire Suppression System Inoperable Due to Personnel Error in Administratively Controlling the MCC Room Exit Door. This issue involved personnel blocking open the Unit 1 cable vault upper level MCC room exit door without establishing provisions to shut the door if a fire in the area would have occurred. This issue was discussed in Inspection Report 280,281/91-29 and was left open because the licensee had not completed corrective actions. The licensee has installed signs on fire doors that explain the special precautions that must be followed when the door is open.

Within the areas inspected, no violations were identified.

11. Exit Interview

The inspection scope and results were summarized on March 9, 1992, with those individuals identified by an asterisk in paragraph 1. The following summary of inspection activity was discussed by the inspectors during this exit.

Item Number	Status	Description and Reference
VIO 50-280,281/92-04-01	Open	Ineffective Corrective Action Associated With HHSI Pump Lube-Oil Cooler TCVs (paragraph 3.g).
NCV 50-280,281/92-04-02	Closed	Failure to Properly Test the Blackout Relays for Starting Motor Driven AFW (paragraph 10.a).
NCV 50-280,281/92-04-03	Closed	Failure to Properly Test the Average Temperature Portion of ESF Logic Circuits (paragraph 10.b).
LER 50-280,281/92-002	Closed	4160 Volt Transformer Bus D, E, and F Undervoltage Relay Trip Setpoints Set Below TS Limit Due to Procedural Error (paragragh 10.a).
LER 50-280,281/92-003	Closed	Incomplete Engineered Safety Features Testing Due to Procedural Deficiency (paragraph 10.b).
LER 50-280/91-13	Closed	MCC Room Fire Suppression System Inoperable (paragraph 10.c).

12. Index of Acronyms and Initialisms

ALARA - AS LOW AS REASONABLY ATTAINABLE
AFW - AUXILIARY FEEDWATER

CFR	-	CODE OF FEDERAL REGULATIONS
CNS	-	CORPORATE NUCLEAR SAFETY
CT	-	CURRENT TRANSFORMER
DC	-	Design Change
ECCS	-	EMERGENCY CORE COOLING SYSTEM
EDG	-	EMERGENCY DIESEL GENERATOR
EOP	-	EMERGENCY OPERATING PROCEDURE
EP	-	EMERGENCY PROCEDURE
ESF	-	ENGINEERED SAFETY FEATURE
ESGR	-	EMERGENCY SWITCHGEAR ROOM
FRV	-	FEED REGULATING VALVE
FSAR	-	FINAL SAFETY ANALYSIS REPORT
GL	-	GENERIC LETTER
HHSI	-	HIGH HEAD SAFETY INJECTION
I&C	-	INSTRUMENTATION AND CALIBRATION
IN	-	INFORMATION NOTICE
INPO	-	INSTITUTE OF NUCLEAR POWER OPERATION
IOER	-	INDEPENDENT OPERATIONAL EVENT REVIEW
IPE	-	INDEPENDENT PLANT EVALUATION
IR	-	INDEPENDENT REVIEW
IRPI	-	INDIVIDUAL ROD POSITION INDICATION
ISI	-	INSERVICE INSPECTION
LCO	-	LIMITING CONDITIONS OF OPERATION
LOCA	-	LOSS OF COOLANT ACCIDENT
LER	-	LICENSEE EVENT REPORT
MCC	-	MOTOR CONTROL CENTER
MOD	-	MOTOR OPERATED DAMPER
MOV	-	MOTOR OPERATED VALVE
MSRC	-	MANAGEMENT SAFETY REVIEW COMMITTEE
NCV	-	NON-CITED VIOLATION
NRC	-	NUCLEAR REGULATORY COMMISSION
OPS	-	OPERATIONS
PAR	-	PROCEDURE ACTION REQUEST
QA	-	QUALITY ASSURANCE
QMT	-	QUALITY MAINTENANCE TEAM
RHR	-	RESIDUAL HEAT REMOVAL
RPM	-	REVOLUTIONS PER MINUTE
RSST	-	RESERVE STATION SERVICE TRANSFORMER
SA/QV	-	SAFETY ANALYSIS/QUALITY VERIFICATION
SI	-	SAFETY INJECTION
SNSOC	-	STATION NUCLEAR AND SAFETY OPERATING COMMITTEE
SW	-	SERVICE WATER
TCV	-	TEMPERATURE CONTROL VALVE
TPUP	-	TECHNICAL PROCEDURE UPDATE PROGRAM
TS	-	TECHNICAL SPECIFICATIONS
UV	-	UNDERVOLTAGE
VPAP	-	VIRGINIA POWER ADMINISTRATIVE PROCEDURES
VPASS	-	VIRGINIA POWER ACTION STATEMENT SYSTEM