UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-280/95-06 and 50-281/95-06

Licensee: Virginia Electric and Power Company
Innsbrook Technical Center
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: March 5 through April 1, 1995

Lead Inspector: L. W. Garner For — 4-13-95
M. W. Branch, Senior Resident Inspector — Date Signed

Inspectors: D. M. Kern, Resident Inspector
S. G. Tingen, Resident Inspector

Approved by: G A Belisle — 4/13/95
G. A. Belisle, Section Chief — Date Signed
Reactor Projects Section 2A
Division of Reactor Projects

## SUMMARY

Scope:

This routine resident inspection was conducted on site in the areas of plant status, operational safety verification, maintenance inspections, surveillance inspections, plant support, action on previous inspection items, and on-site engineering. Inspections of backshift and weekend activities were conducted on March 10, 19, 20, 21, 28 and 30, 1995.

Results:

Operations

A violation was identified for exceeding the 100 degrees F per hour technical specification pressurizer heatup rate on February 4, 1995, during a Unit 2 shutdown evolution (paragraph 7.2).

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Maintenance

Work plan development on the Unit 2 main generator Voltage Regulator (VR) repair, and return of the VR to automatic control were performed in a professional manner (paragraph 4.1).

During Unit 2 Motor Operated Valve (MOV) testing, operators followed procedures, craft were knowledgeable of the MOV diagnostic test equipment, and the system engineer efficiently coordinated the efforts of operations and craft personnel while performing the test (paragraph 5.1).

An apparent violation, pertaining to Unit 2 power operation from June 24, 1994 to February 3, 1995, with three channels of low pressurizer pressure reactor trip protection and three channels of low-low pressurizer pressure Engineered Safeguards Action instruments inoperable was identified (paragraph 5.2).

Engineering

Nuclear engineers and operations personnel communicated effectively to maintain plant parameters within prescribed conditions for physics testing (paragraph 3.2).

Plant Support

During the Unit 2 refueling outage, station personnel provided appropriate focus to minimize personnel exposure and solid waste generation (paragraph 6).

## REPORT DETAILS

1. Persons Contacted

Licensee Employees

*W. Benthall, Supervisor, Licensing
*H. Blake, Jr., Superintendent of Nuclear Site Services
*R. Blount, Superintendent of Maintenance
*M. Bowling, Manager Nuclear Licensing
D. Christian, Station Manager
J. Costello, Station Coordinator, Emergency Preparedness
D. Erickson, Superintendent of Radiation Protection
*R. Garner, Outage & Planning
B. Hayes, Supervisor, Quality Assurance
D. Hayes, Supervisor of Administrative Services
*D. Llewelyn, Superintendent, Nuclear Training
C. Luffman, Superintendent, Security
*J. McCarthy, Assistant Station Manager
*A. Price, Assistant Station Manager
*S. Sarver, Superintendent of Operations
K. Sloane, Superintendent of Outage and Planning
*E. Smith, Site Quality Assurance Manager
*D. Sommers, Supervisor, Corporate Licensing
T. Sowers, Superintendent of Engineering
*S. Stanley, Supervisor, Station Procedures
*J. Swientoniewski, Supervisor, Station Nuclear Safety
*T. Williams, Manager QA

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

NRC Personnel

*M. Branch, Senior Resident Inspector
D. Kern, Resident Inspector
S. Tingen, Resident Inspector
*A. Belisle, Section Chief

*Attended Exit Interview

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

2. Plant Status

Unit 1 operated at full power for the entire inspection period.

Unit 2 started the inspection period with the reactor in cold shutdown. A RFO was in progress. Reactor startup began on March 19 and the

turbine was placed on-line on March 21. The Unit 2 RFO was completed in 47 days. The unit was operating at full power at the close of the inspection period.

3. Operational Safety Verification (71707, 61710)

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 operational safety and compliance with TSs and to maintain overall facility operational awareness. 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.

3.1 Unit 2 Containment Walkdown

On March 14, the inspectors walked down the Unit 2 containment. All RFO maintenance was complete and the inspectors verified that containment was in a condition to support unit operation. The inspectors verified that the containment sump was clean and that the remaining containment areas were reasonably free of debris. The inspectors concluded that the overall condition of the containment was adequate.

During previous inspections the inspectors have questioned the acceptability of plant operation with the refueling transfer canal drain valves closed (see NRC IR 50-280, 281/94-31). The inspectors verified, prior to the Unit 2 startup, that refueling transfer canal drain valves (RL-11 and 12) were open based on a valve lineup dated March 10, 1995.

3.2 Unit 2 Startup from Refueling Outage

The inspectors observed Unit 2 startup and low power physics testing activities on March 19-21. Communications and control of activities within the control room were good. This was the first reactor startup following core reload. Operators were briefed to anticipate criticality at any point during the startup and to closely monitor the performance of a new IRNI detector which had been replaced during the outage. Criticality was achieved very close to the estimated critical position. Reactor power was stabilized at approximately 1% power for physics testing.

Nuclear engineers conducted a detailed pre-evolution brief for low power testing. Operators' questions regarding allowed plant conditions were clearly answered. Several IRPIs did not track

properly with control bank movement during physics testing. Operators appropriately halted testing and had the IRPIs adjusted to match control rod bank demand position. Engineers verified that the effected control rods were correctly positioned and were not misaligned as the IRPIs had indicated. The inspectors observed that nuclear engineers and operations personnel communicated effectively to maintain plant parameters within prescribed conditions for physics testing.

The inspectors observed turbine startup and vibration monitoring. Control room operators communicated closely with vendor personnel during turbine roll-up to verify acceptable turbine vibration. Operators exercised due caution when performing front panel trip checks. The turbine was placed on-line at 5:28 a.m., on March 21. Operators manually maintained steam generator levels as the turbine was loaded.

Within the areas inspected, no violations or deviations were identified.

4. Maintenance Inspections (62703)

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

4.1 Unit 2 Main Generator VR Repair

The main generator exhibited voltage instability following unit startup. Engineers and vendor personnel formed a VR task team to identify the cause and recommend action to correct the voltage instability. The team determined that vendor personnel had not properly connected generator field forcing overexcitation protection circuitry during outage maintenance activities. The inspectors monitored resulting corrective maintenance activities to verify appropriate measures were established to preclude tripping the unit.

On March 29, the VR task team presented their findings and a corrective maintenance work plan to SNSOC for approval. SNSOC closely reviewed the team findings and thoroughly questioned each aspect of the on-line repair plan. Discussions included VR cabinet vibration, positive identification of relays and contacts, ICCE process controls, lessons learned from previous Unit 1 VR work, worker communications, and interfaces between the station and the off-site grid load dispatcher. The inspectors observed that SNSOC carefully evaluated whether the repair should be done on-line or with the unit off-line. The decision to perform the VR repair on-line and the detail of the work plan were sound.

The inspectors observed the repair prebrief and the corrective maintenance to the VR circuits. An additional reactor operator was assigned to operate and monitor the main turbine generator

controls in the control room. Communications were established between this reactor operator and the repair crew in the turbine building. Operations personnel coordinated closely with the load dispatcher when shifting the VR from automatic control to base load control to support the repair. The system engineer led the repair effort and closely directed maintenance personnel through all portions of the repair plan. The inspectors particularly noted excellent step by step communications between the system engineer and the electricians in the high noise work environment at the VR control cabinet. The inspectors concluded that work plan development, VR repair, and return of the VR to automatic control were performed in a professional manner.

4.2 Review of Work Controls and Streamlining Efforts

In order to expedite work processes, several new initiatives were implemented during the Unit 2 RFO in the area of MOV testing and breaker maintenance. MDAP-0002, Conduct of Maintenance, revision 2 was changed to allow the craft to review and sign MOV diagnostic partial clearance forms, remove/install danger tags, and operate the required breaker to energize MOVs in order to perform diagnostic testing. Partial clearances were previously performed by operations personnel. MDAP-0002 was also revised to allow the craft to relocate danger tags when removing and installing a breaker in order to perform maintenance. The inspectors verified that craft personnel were trained on these new work process methods. The inspectors also reviewed deviation reports initiated during the RFO due to tagging discrepancies and verified that these new initiatives in danger tagging did not result in any DRs.

4.3 Modification to Waterproof MOV Operators

On March 5 through 9, the inspectors monitored portions of DCP 93-17-03, Modify CW Limitorque Motor Operators to be Submersible, Surry/Units 1 and 2, field change 8. This design change modified the eight condenser CW inlet MOV actuators to make them watertight. Watertight actuators would enhance MOV operation if these actuators were to become submersed in water during a turbine building flood. The inspectors witnessed the modifications implemented by the design change and testing associated with 2-CW-MOV-206D. The design change was accomplished by WO 284426-01 and 0-ECM-1504-01, Limitorque SMB Type MOV Operator Maintenance, revision 1.

After the actuator was modified, an air drop test was performed. The actuator was pressurized to 4.5 psig and the acceptance criteria was that pressure could drop no more than .5 psig within one hour. The actuator failed the air drop test and a new motor was installed. The air drop test was then satisfactorily performed. The inspectors walked down the other CW inlet MOV actuators and verified that they had been modified to be watertight. No deficiencies were noted.

4.4 Review of Unit 2 WO Backlog

Prior to the Unit 2 RFO on February 3, 1995, the inspectors reviewed the licensee's WO backlog status. Prior to the outage, Unit 2 had 3277 open WOs of which 2360 WOs were classified as outage related and 824 WOs were classified as non-outage related. After the outage completion, there were 1189 open WOs of which 401 WOs were classified as outage related and 788 WOs were classified as non-outage related. The inspectors concluded that the licensee was effectively tracking their WO backlog. WOs were not reclassified to reduce outage work scope.

4.5 Review of Selected RFO Maintenance and Testing Activities

During previous Unit 2 power operations, equipment degradation and failures resulted in either plant transients or off-normal plant operations. During this RFO, the inspectors monitored selected maintenance and testing activities associated with correcting these equipment problems.

Previously jumpered cell 52 and 17 other cells were replaced in Station Battery 2A. Work was performed per WO 303202-01 which invoked procedure 0-ECB-D102-01, Large Exide Stationary Battery Cell Replacement, revision 1.

IRPI coils for rods L-11 and M-10 were replaced per WO 301913-01 and 303204-01, respectively, using procedure 0-ECM-1902-06, CRDM and RPI System Maintenance, revision 0. During the disconnection of the CRDM and IRPI cables to support refueling, the electricians noted that several cables had heat damage. The damaged cables were sleeved with RayChem Kits which repaired the insulation damage.

During the RFO, CRDR enhancements associated with main control board single filament indicator bulb testing and replacement were implemented. New bulbs were tested (WO 313440-01) prior to replacement. The old bulbs were also tested as part of the process and no failures were identified. There were 11 bulbs involved in this maintenance activity.

The inspectors verified that Operations personnel were monitoring the component cooling system radiation monitor when the Unit 2 excess letdown heat exchanger was pressurized during the ISI hydrostatic test. Based on a review of station records, no alarms were received when the heat exchanger was pressurized which indicated tube integrity in the heat exchanger.

Within the areas inspected, no violations or deviations were identified.

5. Surveillance Inspections (61726)

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

5.1 MOV DP Testing

On March 13, the inspectors witnessed the performance of 2-PT-25.1, Quarterly Testing of CW and SW System Valves, revision 3. This test verified that valves 2-SW-MOV-202A and B would shut at maximum DP. The test was being accomplished to meet the requirements of GL 89-10, Safety-Related Motor-Operated Valve Testing and Surveillance, dated June 28, 1989. In order to obtain maximum DP across the valves, intake canal level was raised to a level of 30 feet and the piping downstream of the valves was depressurized. The valves were instrumented with diagnostic test equipment and satisfactorily opened during the test. Operators followed the procedure, the craft was knowledgeable of the MOV diagnostic test equipment and the system engineer efficiently coordinated the efforts of operations and craft personnel while performing the test. The inspectors were informed by the system engineer that thirteen valves were successfully DP tested during the Unit 2 RFO.

5.2 Calibration Problems Associated With Unit 2 Pressurizer Pressure Transmitters

5.2.1 Licensee's Identification and Evaluation of Problem

On February 10, 1995, during refueling calibrations, all three Unit 2 Pressurizer Protection pressure transmitters were found out of calibration. The Unit had been on line continuously since June 25, 1994. The as-found conditions for the transmitters were: 2-RC-PT-2455 was high by 121 mv; 2-RC-PT-2456 was high 143 mv; and 2-RC-PT-2457 was high 152 mv. These voltages correspond to 24 psig, 28.5 psig, and 30 psig above the allowable setpoint value. A root cause team was formed to evaluate the event and determine the cause of the unusually high indications. The following is a sequence of events and a summary of that root cause evaluation:

Sequence of Events

May 12, 1994 - Bench calibration performed on all three new Rosemount 1154 transmitters designated as 2-RC-PT-2455, 2456, 2457.

June 18, 1994 - After installion of the new transmitters, I&C technicians performed a field calibration. All three transmitters were found out of calibration high and required adjustment. Heise gage M&TE #SQC-437 was used to perform the calibration.

June 21, 1994 - Heise gage SQC-437 was checked into the Metrology Laboratory for its normal quarterly calibration check. No problems were found.

June 24, 1994 - Operations noted that all three protection channels were indicating lower than control channels and DR S-94-1352 was written. Test gage SQC-437 was used to perform calibration check on all three Pressurizer Pressure Protection transmitters. All three transmitters were found out of calibration low and required adjustments.

June 24, 1994 - Unit 2 Critical

June 25, 1994 - Operations received pressurizer pressure alarms and noted that protection channels were reading approximately 15 - 20 psig higher than the control channels.

June 28, 1994 - Heise gage SQC-437 was returned to the Metrology Laboratory for calibration check. The gage was found to be nonrepeatable and low at the high end.

February 10, 1995 - During refueling calibrations, all three Pressurizer Pressure Protection transmitters were found out of calibration high and required adjustment.

Licensee's RCE

The licensee's RCE determined that the most probable cause of the calibration error was the use of a non-temperature compensated test gage. Test gage calibrations were affected by 3 psig/5 degrees F change from 73 degrees F. This resulted in an estimated 24 psig error. Additionally, the gage was identified as binding due to inadequate torque during the manufacturing process. The licensee also determined that a contributing cause was inadequate training in using compensated/noncompensated gages.

5.2.2 Inspectors' Review and Assessment of Causes

The inspectors reviewed the licensee's RCE and supporting information. Based on vendor information from the test gage supplier, a non-temperature compensated gage could contribute to a calibration error as much as 3 psig/5 degrees F change from the reference calibrated temperature of 73 degrees F. The inspectors reviewed operator's logs for temperature in containment. The logs reviewed did not provide an ambient temperature during shutdown. However, other data indicated that ambient conditions were at the

reference temperature. Containment temperature during hot shutdown and power operations is normally between 100 - 115 degrees F and therefore the licensee's assumptions of error associated with use of a non-temperature compensated gage was reasonable.

The licensee used the same non-temperature compensated test gage to calibrate all three pressurizer pressure channels and along with minor binding of the bourdon tube resulted in the (worst case of the three) pressure transmitters reading approximately 30 psig greater than actual pressure.

After determining that non-temperature compensated test gages were in the M&TE system, the licensee confiscated all these type gages and locked them up. The RCE also determined that the licensee had to flush all gages that had been used in contaminated systems prior to release to the non-contaminated calibration facility for calibrations.

The inspectors reviewed the two DRs issued by operations when the instrument error was initially identified in June 1994. The first DR (S-94-1352) was dispositioned by maintenance as a personnel error associated with difficulties in reading the test gage during calibration while in a respirator. The second DR (S-94-1353), issued after alarms were received during unit startup, was closed out due to the corrective actions of DR S-94-1352. These two DRs provided early opportunities for recognition and correction which could have prevented unit operation with degraded pressurizer pressure channels.

Another opportunity to identify and correct the above condition occurred when M&TE test gage SQC-437 was found out of calibration on June 28, 1994. Had the intent of VPAP-1201, Control of M&TE, revision 2, been followed, a re-calibration of the three pressurizer pressure transmitters would have occurred with a different test gage. Specifically, the following requirements of VPAP 1201 were not followed:

1) Section 6.3.2.b states, "The reliability and accuracy of M&TE may be affected based on environmental conditions (e.g., temperature extremes, high humidity, etc.) The use of M&TE in such environmental conditions shall be in accordance with manufacturer's equipment specifications". This was not done.

2) Section 6.6 requires an evaluation be performed whenever M&TE is found out of calibration. The stated purpose of the evaluation was to review the impact of the out-of-spec readings on plant equipment that may

have been calibrated with questionable M&TE. The as-found error of the M&TE is required to be compared against the tolerance of the plant equipment calibration procedure. If the M&TE error exceeds the allowable tolerance of the acceptance criteria for the plant equipment, then the calibration is invalid and must be repeated if justification to do otherwise cannot be found and documented. The evaluation performed when M&TE test gage SQC-437 was found out of calibration on June 28, 1994, did not require a re-calibration of affected plant equipment and attributed the problem to disassembly of the test gage for decontamination which is prohibited by Section 6.4.4.e.2 of VPAP 1201.

5.2.3 Review of Safety Significance

The February 10, 1995, as-found calibration error associated with each of the three pressurizer pressure transmitters was evaluated by electrical engineering. The inspectors reviewed this evaluation dated February 20, 1995. The evaluation compared the actual calibration error found for each transmitter with the error assumed in the instrument set-point calculation. The transmitter error was tabulated along with other instrument loop errors to determine the overall error associated with the reactor trip and ESA channels. The impact of the instrument loop error on low pressurizer pressure reactor trip and low-low pressurizer pressure ESA events was calculated. The margin between the value used in the SA and the actual pressure where the channel would actuate the safety function was determined. In all cases, the TS allowable values and SA values were exceeded and, therefore, the pressure channels were inoperable. The worst case low pressurizer pressure reactor trip point was 21.38 psig below the 1850.3 psig used in the SA and the worst case low-low pressurizer pressure ESA was 31.38 psig below the SA value of 1700.3 psig. The worst case values were rounded to 22 psig and 32 psig and this information was provided to the licensee's NAF group for review.

The NAF review was documented in ET no. NAF-95031, Evaluation of Impact on Safety Analyses Pressurizer Pressure Transmitters for RPS Input, Surry Power Station, Unit 2, revision 0. This evaluation analyzed the impact of the worst case setpoint errors on the SA for DNB plant transients, steam line break, and large and small break LOCAs. The evaluation determined that the worst case error would result in a slight reduction of SA margin but was still bounded by the SA for the cycle 12 operation (the period of time that the instruments were

inoperable). The NRC questioned why ET NAF-95031, revision 0, did not review the error's impact on a SG tube rupture event. This was discussed with the licensee and NAF-95031 was revised to include this information without changing the results of the review. The inspectors, along with other NRC staff, found the licensee's safety impact review acceptable.

5.2.4 Regulatory Issues

Technical Specifications 3.7.B which references TS Table 3.7-1, and TS 3.7.C which references TS Table 3.7-2, requires that Reactor Protection and Engineered Safeguards Action channels and interlocks be operable as specified in their respective tables. TS Table 3.7-1, item 7, including Operator Action 7 requires a minimum of 2 out of 3 Low Pressurizer Pressure Reactor Trip channels be operable for power operation. TS Table 3.7.2, item 1.d, including Operator Action 20 requires a minimum of 2 out of 3 Pressurizer low-low pressure channels be operable for power operations.

In summary, because of instrument calibration errors, Unit 2 operated at power from 9:25 pm on June 24, 1994, to 3:08 am on February 3, 1995, with all three pressurizer low pressure reactor trip and pressurizer pressure low-low ESA channels inoperable. This item is identified as Apparent Violation EEI 50-281/95-06-01, Operation With All Three Channels of Pressurizer Pressure Low Reactor Trip and Pressurizer Pressure Low-Low ESA Inoperable.

Within the areas inspected, one apparent violation was identified.

6. Plant Support (71750)

The station established radiological performance goals for volume of sold waste generated and cumulative personnel radiation exposure. Station management remained actively involved in tracking performance indicators to assess RP performance throughout the outage. The inspectors attended daily work status briefings and frequently toured Unit 2 radiological work areas to observe RP practices. RP technicians provided comprehensive job coverage throughout the outage. Both the personnel exposure and solid waste generation goals were achieved. The total personnel exposure for the RFO was 157.7 Rem which is the lowest RFO exposure achieved to date. The inspectors concluded that station personnel provided appropriate focus to minimize personnel exposure and solid waste generation.

Within the areas inspected, no violations or deviations were identified.

7. Action on Previous Inspection Items (92901, 92902)

7.1 (Closed) VIO 50-280/93-23-01, Fuse Removal Not Accomplished in Accordance with Tagging Record and OPAP-0010.

This issue involved electricians removing and danger tagging the wrong fuses when establishing isolation for a maintenance evolution. In a letter dated November 19, 1993, the licensee stated that electricians were not adequately trained or properly qualified to install and verify electrical danger tags and that the station tagging policy was revised to only allow Operations personnel to install/remove electrical or mechanical danger tags.

The inspectors reviewed the station tagging policy contained in VPAP-1402, Control of Equipment, Tag-Outs and Tags, revision 2, OPAP-0010, Tag-Outs, revision 4, and MDAP-0002 and concluded that the station policy to allow Operations personnel to install/remove electrical or mechanical danger tags had been revised to allow electricians to install/remove electrical danger tags in certain instances. VPAP-1402, Paragraph 4.2, discussed when electricians are allowed to remove/install danger tags. The inspectors also verified that electricians were trained. The inspectors concluded that the revised policy was acceptable in that electricians were thoroughly trained.

7.2 (Closed) URI 50-281/95-03-01, Unit 2 Pressurizer Excessive Heatup Rate

On February 4, 1995, pressurizer heatup rate exceeded the 100 degrees F per hour TS limit during an RCS degas evolution. The licensee identified that a 146 degrees F pressurizer heatup occurred in one hour as operators adjusted charging flow to maintain pressurizer level. Appropriate immediate actions were taken to stop the pressurizer heatup and procedure revisions were initiated to more clearly alert operators to the potential for excessive heatup/cooldown during degas operations. This issue remained unresolved pending inspector's review of the pressurizer fatigue analysis.

IR 50-280, 281/95-03 discussed in detail the conditions that caused the pressurizer heatup event. Based on recent industry events the licensee had modified their procedure to increase operator sensitivity to pressurizer thermal transients. During this event, operators had successfully terminated an unexpected pressurizer cooldown because of their increased sensitivity to thermal transients. However, plant conditions established for RFO electrical surveillance testing hampered the operator's ability to effectively control this event to prevent exceeding TS limits. The licensee recently indicated that an industry group is currently reviewing known startup and shutdown plant evolutions to determine if better controls can be established to prevent future events of this nature.

The vendor performed a pressurizer fatigue analysis to assess the effects of the excessive heatup on pressurizer integrity. Station records did not document pressurizer temperatures on an hourly basis. Therefore, the licensee established 40 similar heatup transients as a bounding case to account for potential excess heatups during the current 40 year license. The inspectors determined that this assumption was valid. The fatigue analysis determined that the pressurizer inner wall was the limiting component and concluded that cumulative fatigue was within pressurizer design. The resident inspectors discussed the fatigue analysis with licensee personnel. It was determined that the analysis was technically sound and that the fatigue associated with this event was within pressurizer design.

TS 3.1.B.3 requires that pressurizer heatup rate not exceed 100 degrees F per hour. On February 4, 1995, from 10:30 a.m. to 11:30 a.m., the Unit 2 pressurizer temperature increased 146 degrees F (from 254 to 400 degrees) in one hour. This excessive heatup is identified as VIO 50-281/95-06-02, Pressurizer Excessive Heatup Rate.

Within the areas inspected, one violation was identified.

8. On-Site Engineering (37551)

8.1 Unit 2 HHSI Pump Motor Evaluation

NRC IR 50-280, 281/95-03 discussed a design issue associated with the power requirements for the Unit 2 C HHSI pump motor. Testing identified that the maximum motor power requirement was 711 HP which exceeded the design value of 690 HP. The motor manufacturer, Westinghouse, was contacted and evaluated motor operation at 711 HP.

The inspectors reviewed Engineering Report CEE 95-23, HHSI Pump Motor Overduty, dated March 10, 1995. The report concluded that the motor was operable and that EDG loading would not exceed the 2000-hour rating. The inspectors reviewed the Unit 2 HHSI pump head curve and noted that the flow rates obtained during the latest and previous flow rate tests were within twenty GPM of the curve. The inspectors concluded that small flow deviations from the pump head curve resulted in large changes in motor power requirements. The inspectors also concluded that the licensee satisfactorily resolved this issue prior to Unit 2 restart.

8.2 Pressure Locking of PWR Containment Sump Recirculation Gate Valves (NRC TI 2515/129)

The inspectors reviewed the licensee's activities to evaluate susceptibility of the CSRSVs (1-SI-1860A/B and 2-SI-1860A/B) to the pressure locking phenomenon. These valves are designed to

open and provide a flow path from the containment sump to the LHSI pumps for long term decay heat removal following a design basis LOCA.

Initial assessment by the licensee indicated that the likelihood of pressure locking would be greatly reduced or eliminated by maintaining the containment sump suction piping full of water. The containment sump suction piping and CSRSVs are located at a lower elevation than the containment sump. Operations personnel visually verified the presence of water in the Unit 2 containment sump and associated piping prior to restart. Engineers observed water in the Unit 1 containment sump during the December 1994 outage. Operations and engineering personnel are developing a plan to verify water in the containment sump during periodic containment entries while at power and prior to each unit startup. Engineering initiated a UFSAR change to document this design basis configuration change. The inspectors determined that these actions were appropriate pending completion of a formal engineering evaluation regarding susceptibility to CSRSV pressure locking.

The licensee performed engineering evaluation ET CME 95-0018, Engineering Review of OE 7107, revision 0, to evaluate applicability of CSRSV pressure locking at Surry Station. The evaluation concluded that 1-SI-1860A/B and 2-SI-1860A/B were not susceptible to pressure locking provided that the piping between the containment recirculation sump and these valves was maintained full of water. The inspectors independently reviewed ET CME 95-0018, the UFSAR, interviewed personnel, and visually inspected associated valves and piping to evaluate the licensee's conclusions.

The inspectors determined that assumptions used in evaluating ET CME 95-0018 were generally conservative. Assumed initial and post DBA LOCA containment sump temperatures were more severe than specified in the UFSAR. The inspectors reviewed station drawings and visually inspected suction piping in the valve pits. The actual piping length from the containment sump to the suction valves was greater than assumed in the evaluation. Additionally, credit was not taken for heat dissipation from the suction piping to the surrounding concrete embedment. Worst case assumptions were also factored for valve seat leakage, packing leakage, and presence of water inside the valve bonnet. The resulting calculated heatup rate inside the valve bonnet was 0.2 degrees F per hour. Engineering determined that the DBA LOCA leakrate would necessitate shifting from LPCI to LPCI recirculation mode within 1 hour of the accident start. This resulted in a 0.2 degrees F heatup of the water inside the valve bonnet and a maximum bonnet pressure of 52 psig when the valve would be required to open. The evaluation concluded that valve operator design was sufficient to overcome this amount of pressure within the bonnet.

The inspectors observed that the heat transfer calculations within ET CME 95-0018 were technically sound. However, the evaluation did not address heat transfer to and from the atmosphere surrounding the valve or heat transfer from the sump to the valve via the piping metal. Engineering informed the inspectors that ET CME 95-0018 would be revised to address this concern. Subsequent to the inspection period, ET CME 95-0018 was revised and reviewed by the inspectors. The inspectors concluded that the licensee's actions to evaluate and address CSRSV pressure locking were appropriate.

8.3 Shutdown Risk Assessment

SNS engineers performed an independent safety assessment of the outage activity schedule in accordance with VPAP-2805, Shutdown Risk Program, revision 1, to support safe integration of Unit 2 RFO maintenance activities. The Unit 2 Refueling Outage Assessment Report was completed and distributed prior to the start of the RFO. The inspectors reviewed VPAP-2805, the Outage Assessment Report, the outage work schedule, and daily reassessments of safety critical parameters during the outage to determine whether shutdown risk was properly managed.

VPAP-2805 provided detailed guidance regarding shutdown safety system availability criteria. Several system requirements, in addition to TS requirements, were specified to implement a defense in depth philosophy. The supplemental safety system requirements encompassed decay heat removal, RCS inventory addition, reactivity control, electrical power sources, and SFP operations.

The inspectors reviewed the Outage Assessment Report and observed that scheduled activities which had the potential to degrade critical shutdown safety attributes below established acceptance criteria were clearly identified and evaluated. Where appropriate, the outage activities were rescheduled to maintain acceptable availability of critical safety equipment. One example was a conflict between the monthly #3 EDG operability surveillance test and maintenance on the B RSST. Maintenance on the B RSST required both Unit 2 4160 volt emergency buses to be supplied from the C RSST. The #3 EDG was the only available emergency power supply to these buses in the event the C RSST failed. Unavailability of a backup power supply to the Unit 2 emergency buses was identified as an unacceptable condition. The #3 EDG surveillance was rescheduled to eliminate this conflict. The inspectors determined that the outage schedule had been thoroughly evaluated and revised where appropriate to provide acceptable defense in depth.

The outage schedule was frequently revised to accommodate resource, work scope, and activity duration changes. The licensee used a computer application to assist in developing the Outage Assessment Report. The computer model tracked the impact of

outage activities on critical safety parameters including reactivity, core cooling, electrical power availability, containment, and RCS integrity. SNS engineers effectively used this model to reassess the schedule on a daily basis during the outage. The inspectors reviewed selected daily shutdown safety assessments and the resulting addendum to the Outage Assessment Report. Schedule revisions were evaluated in a timely manner and addendum to the Outage Assessment Report were issued before the schedule changes became effective. The inspectors concluded that SNS review of outage activities was comprehensive and the licensee had properly managed shutdown risk.

Within the areas inspected, no violations or deviations were identified.

9. Exit Interview

The inspection scope and findings were summarized on April 5, 1995, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results addressed in the Summary section and those listed below.

| Item Number | Status | Description/(Paragraph No.) |
|---|---|---|
| EEI 50-281/95-06-01 | Open | Operation With All Three Channels of Pressurizer Pressure Low Reactor Trip and Pressurizer Pressure Low-Low ESA Inoperable (paragraph 5.2). |
| VIO 50-281/95-06-02 | Open | Pressurizer Excessive Heatup Rate (paragraph 7.2). |
| VIO 50-280/93-23-01 | Closed | Fuse Removal Not Accomplished in Accordance with Tagging Record and OPAP-0010 (paragraph 7.1). |
| URI 50-281/95-03-01 | Closed | Unit 2 Pressurizer Excessive Heatup (paragraph 7.2). |

Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

10. Index of Acronyms

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|---|---|
| CFR | CODE OF FEDERAL REGULATIONS |
| CRDM | CONTROL ROD DRIVE MECHANISM |
| CRDR | CONTROL ROOM DESIGN REVIEW |
| CSRSV | CONTAINMENT SUMP RECIRCULATION SAFETY VALVE |
| CW | CIRCULATING WATER |
| DBA | DESIGN BASIS ACCIDENT |

| | |
|---|---|
| DCP | DESIGN CHANGE PACKAGE |
| DNB | DEPARTURE FROM NUCLEATE BOILING |
| DP | DIFFERENTIAL PRESSURE |
| DR | DEVIATION REPORT |
| ECCS | EMERGENCY CORE COOLING SYSTEM |
| EDG | EMERGENCY DIESEL GENERATOR |
| EEI | ESCALATED ENFORCEMENT ITEM |
| ESA | ENGINEERED SAFEGUARDS ACTION |
| F | FAHRENHEIT |
| GL | GENERIC LETTER |
| GPM | GALLONS PER MINUTE |
| HHSI | HIGH HEAD SAFETY INJECTION |
| HP | HORSEPOWER |
| ICCE | INFREQUENTLY CONDUCTED OR COMPLEX EVOLUTION |
| I&C | INSTRUMENTATION AND CONTROL |
| IR | INSPECTION REPORT NOS. |
| IRPI | INDIVIDUAL ROD POSITION INDICATION |
| IRNI | INTERMEDIATE RANGE NUCLEAR INSTRUMENT |
| ISI | INSERVICE INSPECTION |
| LHSI | LOW HEAD SAFETY INJECTION |
| LOCA | LOSS OF COOLANT ACCIDENT |
| LPCI | LOW PRESSURE COOLANT INJECTION |
| M&TE | MEASURING AND TEST EQUIPMENT |
| MOV | MOTOR OPERATED VALVE |
| MV | MILLIVOLT |
| NAF | NUCLEAR ANALYSIS AND FUEL |
| NRC | NUCLEAR REGULATORY COMMISSION |
| NRR | OFFICE OF NUCLEAR REACTOR REGULATION |
| PSIG | POUNDS PER SQUARE INCH GAGE |
| PWR | PRESSURIZED WATER REACTOR |
| QA | QUALITY ASSURANCE |
| RCE | ROOT CAUSE EVALUATION |
| RCS | REACTOR COOLANT SYSTEM |
| RFO | REFUELING OUTAGE |
| RP | RADIATION PROTECTION |
| RPI | ROD POSITION INDICATION |
| RPS | REACTOR PROTECTION SYSTEM |
| RSST | RESERVE STATION SERVICE TRANSFORMER |
| SA | SAFETY ANALYSIS |
| SFP | SPENT FUEL POOL |
| SG | STEAM GENERATOR |
| SNS | STATION NUCLEAR SAFETY |
| SNSOC | STATION NUCLEAR SAFETY AND OPERATING COMMITTEE |
| SW | SERVICE WATER |
| TI | TEMPORARY INSTRUCTION |
| TS | TECHNICAL SPECIFICATION |
| UFSAR | UPDATED FINAL SAFETY ANALYSIS REPORT |
| URI | UNRESOLVED ITEM |
| VR | VOLTAGE REGULATOR |
| VIO | VIOLATION |
| WO | WORK ORDER |