

U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Report No: 50-280/97-03, 50-281/97-03

Licensee: Virginia Electric and Power Company (VEPCO)

Facility: Surry Power Station, Units 1 & 2

Location: 5850 Hog Island Road
Surry, VA 23883

Dates: March 9 - April 19, 1997

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Enclosure 2

EXECUTIVE SUMMARY

Surry Power Station, Units 1 & 2
NRC Inspection Report Nos. 50-280/97-03, 50-281/97-03

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of announced inspections by a regional radiation specialist and regional projects inspectors.

Operations

- During the Unit 1 Refueling Outage (RFO), the licensee failed to properly maintain refueling containment integrity which constituted a violation of Technical Specification (TS) 3.10.A.1 (Section 01.2).
- The inspectors concluded that the licensee could have exhibited a more conservative approach by providing an additional method to monitor spent fuel pit temperature during the period of high pit heat load (Section 01.3).

Maintenance

- Maintenance personnel failed to follow the reactor disassembly procedure in that they did not place RTV along the entire circumference of the inner J-Seal resulting in the cavity seal leak during post installation testing. This is a Violation of TS 6.4.D. The inspectors consider that work practice is the only causal factor described in Deviation Report (DR) 97-0795 to be valid. The procedure is clear and explicit. The inspectors concluded that the response to DR 97-0795 should have been more explicit in that it did not detail the work practice/failure to follow procedure issue. The proposed corrective actions involving revising the procedure are enhancements and will likely not prevent recurrence. The inspectors discussed this with plant management and plant management stated that they would review the issue (Section M1.1).
- The work performed to install 1-SW-MOV-105B was performed properly and in accordance with the specified work instructions. Providing more detailed instructions in the design change and work order was discussed with plant management as a potential enhancement for future tasks of this type (Section M1.2).
- The inspectors determined that the licensee performed the appropriate actions to correct a number of longstanding equipment problems. The effectiveness of these activities will be determined during the next operating cycle (Section M1.3).
- The Inservice Inspection (ISI) period plan, personnel certifications, weld examination, and the ultrasonic examination procedure were in accordance with Code Requirements (Section M2.1).
- The drawing for the upstream elbow weld on Pressurizer Line No. 4"-RC-34-1502 (weld adjacent to Weld No. 3-02) was not depicted on ISI reactor

coolant isometric sketch No. 11448-WKS-0124A1-1. The licensee took actions to have the ISI drawing revised (Section M2.1).

- The review of procedures, personnel certifications and the evaluation of recorded eddy current data for tubes in the A steam generator revealed that Westinghouse personnel were very knowledgeable of the eddy current examination and data analysis process (Section M2.2).
- Virginia Power Company has approximately 5000 components in the Unit 1 flow accelerated corrosion program. Approximately 110 to 121 of these components are scheduled each outage to be examined. A concern was expressed when high component replacement rates were experienced from the small sample of components examined. The licensee issued DR S-97-0895 to address flow accelerated corrosion concerns. Licensee actions planned in response to this deviation were considered good (Section M2.3).

Engineering

- The modification activities reviewed by the inspectors during the RFO should correct two longstanding equipment deficiencies (Section E1.1).
- Based on the deterioration seen in the Unit 1 letdown orifices, the licensee prudently replaced these orifices and associated downstream piping during the 1997 Unit 1 RFO (Section E1.2).
- The inspectors identified a violation involving an inaccurate Licensee Event Report (LER) submittal. The licensee addressed this matter and the associated corrective actions in their response to Violation 50-280, 281/97002-04 (Section E8.1).

Plant Support

- During the Unit 1 RFO, the licensee was properly monitoring and controlling personnel radiation exposure and posting area radiological conditions in accordance with 10 CFR Part 20 (Section R1.1).
- The licensee was maintaining radioactive effluent monitoring instrumentation in an operable condition and performing the required surveillances to demonstrate their operability. The Radiation Monitoring Upgrade Program was considered to be a significant program improvement (Section R1.2).
- The onsite meteorological measurements program was implemented in accordance with the Updated Final Safety Analysis Report (UFSAR) (Section R1.3).
- The licensee was maintaining the Control Room Emergency Ventilation System in an operable condition and performing the required surveillances to demonstrate operability of the system (Section R1.4).

Report Details

Summary of Plant Status

Unit 1 was in a RFO the entire reporting period.

Unit 2 operated at power the entire reporting period.

I. Operations

01 Conduct of Operations

01.1 General Comments (71707, 40500)

The inspectors conducted frequent control room tours to verify proper staffing, operator attentiveness, and adherence to approved procedures. The inspectors attended daily plant status meetings to maintain awareness of overall facility operations and reviewed operator logs to verify operational safety and compliance with TSs. Instrumentation and safety system lineups were periodically reviewed from control room indications to assess operability. Frequent plant tours were conducted to observe equipment status and housekeeping. DRs were reviewed to assure that potential safety concerns were properly reported and resolved. The inspectors found that daily operations were generally conducted in accordance with regulatory requirements and plant procedures.

01.2 Loss of Refueling Containment Integrity

a. Inspection Scope (71707)

The inspectors reviewed instances which resulted in a loss of refueling containment integrity during the Unit 1 RFO.

b. Observations and Findings

On March 20, with Unit 1 in refueling shutdown and fuel movement underway, a licensee manager performing a walkdown of refueling containment integrity penetrations discovered that the blanks on the main steam safety valve flanges were not properly secured. Fuel movement was stopped. A subsequent investigation revealed that the blank installed in the position of main steam safety valve 1-MS-SV-103C had a gap of approximately one-eighth inch between the sealing surfaces. The licensee developed and implemented a containment integrity verification plan which involved checking other penetrations and properly securing the blanks on the main steam safety valve flanges. No additional problems were identified. Fuel movement resumed approximately three and one-half hours after being stopped.

The following day at approximately 10:54 a.m., during a tour of the Unit 1 containment, a member of the licensee's Nuclear Oversight Department discovered that the containment equipment hatch blank flange was not properly closed. Light from outside containment could be seen through the flange seating surface. Fuel movement was again stopped. A more

detailed and effective containment integrity verification plan was implemented. Operations performed a detailed walkdown of all containment penetrations and identified another leakage path. Main Steam Trip Valve, 1-MS-TV-101C, had drifted from the full closed position and was no longer serving as a containment barrier as required. Instrument air had leaked past an isolation valve to the trip valve's actuator causing the valve to partially open. These matters were corrected prior to the resumption of fuel movement.

This matter was reported to the NRC in accordance with 10 CFR 50.73 (LER 50-280/97006-00). In this report, the licensee stated that the requirements of 10 CFR 100 would not have been exceeded in regards to this matter if a postulated fuel handling accident had occurred with the containment conditions as stated. The inspectors reviewed the licensee's evaluation and concurred with the licensee's conclusion.

The failure to maintain all penetrations which provide a direct path from containment atmosphere to the outside atmosphere closed is a violation of TS 3.10.A.1. The failure to maintain refueling containment integrity during fuel movement will be tracked as Violation 50-280/97003-01.

c. Conclusions

During the Unit 1 RFO, the licensee failed to properly maintain refueling containment integrity during fuel movement which constituted a violation of TS 3.10.A.1.

01.3 Spent Fuel Pit Temperature Monitoring (71707)

On March 23, the day following the completion of the Unit 1 full core offload, the inspectors reviewed the licensee's methods of monitoring spent fuel pit temperature. Normally, a temperature indicator on both the Unit 1 and 2 control panels displays the spent fuel pit temperature. Additionally, two alarms for spent fuel pit high temperature (high and high-high temperature) are normally available through the control room annunciator system. On the date of this review and for the previous five days, only the temperature indicator on the Unit 2 panel remained operable. The remainder of the equipment was out of service due to an ongoing modification involving a portion of the non-safety related instrument racks. To compensate for this condition, operations personnel were logging spent fuel pit temperature on an hourly basis and were well aware of the equipment status. The inspectors concluded that the licensee could have exhibited a more conservative approach by providing an additional method to monitor the spent fuel pit temperature during this period of high spent fuel pit heat load.

08 Miscellaneous Operations Issues (92901)

- 08.1 (Closed) LER 50-281/95001-00: pressurizer heatup exceeded TS limit due to lack of procedural control. On February 4, 1995, the Unit 2 operators noted that the pressurizer cooldown rate was close to the

200° Fahrenheit per hour (F/hr) cooldown allowed by TS 3.1.B.3. The operators slowed the cooldown rate and submitted DR 95-0206. A review of the data taken during the performance of General Operating Procedure 2-GOP-2.6, "Unit Cooldown, Less Than 205° F to Ambient," revealed that the TS specified cooldown rate had not been exceeded. However, the data indicated that the pressurizer temperature increased from 254° F to 400° F in a one hour period which exceeds the TS specified limit of 100° F/hr. DR 95-0218 was issued to describe this event. This event is described in detail in Inspection Reports (IRs) 50-280, 281/95003 and 50-280, 281/95006.

The licensee attributed the event to inadequate procedural controls for pressurizer in-surges and out-surges during the Reactor Coolant System (RCS) cooldown which was due to lack of operating experience. In addition the operators did not anticipate a heatup during RCS cooldown evolutions. The licensee initiated training on the event and revised Procedure 1/2-GOP-2.6. Westinghouse performed an analysis of the effects of the transient on the pressurizer. The analysis revealed that the transient had no detrimental structural effects on the pressurizer.

The Westinghouse Owners Group (WOG) created a task team on pressurizer in-surge and out-surge transients. The team collected data on pressurizer heatup and cooldown rates. The WOG completed their review and on February 3, 1997, issued a set of guidelines to mitigate these events. The results of the review were documented in WCAP-13588, "Operating Strategies for Mitigating Pressurizer Insurge and Outsurge Transients," dated March 1993 and WCAP-14717, "WOG Evaluation of the Effect of Insurge/Outsurge Out of Limit Transients on the Integrity of the Pressurizer (Program MUHP-5063 Summary Report)," dated August 1996. The licensee plans to evaluate the results and recommendations of the task team. The following procedures were revised as a result of the guidelines:

- OSP-RC-001, "RCS and Przr Heatup/Cooldown Verification,"
Revision 1
- GOP-1.1, "Unit Startup, RCS Heatup From Ambient to 195° F,"
Revision 9
- GOP-1.2, "Unit Startup, RCS Heatup From 195° F to 345° F,"
Revision 9
- GOP-2.4, "Unit Cooldown, Hot Shutdown to 351° F," Revision 9
- GOP-2.5, "Unit Cooldown, 351° F to 201° F," Revision 7
- GOP-2.6, "Unit Cooldown, 201° F to Ambient," Revision 7

The inspectors verified that the changes had been made to the procedures.

The inspectors reviewed the heatup and cooldown data of February 4, 1995, contained in GOP-2.6; Westinghouse evaluation RM06-1566, dated February 13, 1995; and the training lesson plans. Training records were reviewed and the inspectors verified that training had been given. The licensee has completed their planned corrective actions.

- 08.2 (Closed) Violation 50-281/95006-02: pressurizer heatup rate exceeded TS limits of 100° F/hour. This violation was written against the event described in Section 08.1 (LER 50-281/95001-00). The inspectors reviewed the licensee's response dated June 15, 1995, and determined that it was acceptable. The closure of the LER 50-281/95001-00 also closes this item.
- 08.3 (Closed) LER 50-280/97006-00: loss of refueling integrity due to an inadequate containment closure process. The corrective actions related to this LER will be tracked by Violation 50-280/97003-01.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Reactor Cavity Seal Ring

a. Inspection Scope (62707)

On March 16, 1997, following installation of the cavity seal ring, the licensee performed the cavity level air drop test. The test failed because of excessive leakage. The inspectors reviewed the DRs and verified the licensee's corrective actions.

b. Observations and Findings

The licensee installed the cavity seal ring in accordance with 0-MCM-1150-01, "Reactor Disassembly And Reassembly," Revision 4, Section 6.11, "Reactor Cavity Seal Ring And Strongback Installation." A visual inspection of the seal ring following the failed test revealed that there were two areas, each about 10 inches long, where the inner J-Seal was not touching the reactor vessel (1/8" gap). Additionally, the licensee determined that they had failed to place RTV along the entire circumference of the inner J-Seal. The licensee also identified that six of the 20 capscrews in the diaphragm plate manway nearest the cavity ladder were loose (not even hand tight). The outer J-Seal had been sealed to the diaphragm plate foam using RTV, but the RTV had migrated under the seal ring standoffs which did not allow the seal to settle into position. These items caused the seal to leak by when the inflatable seal was deflated. The seal ring was removed from the cavity and one inner segment ring was found to be bent. The bent segment was removed, straightened, and reinstalled. RTV was placed as required by procedures. The air drop test was successfully repeated. No leakage was observed and both seals inflated and deflated as designed. Two DRs, 97-0782 and 97-0975, were issued by Engineering and Maintenance respectively to track this issue.

The causal factors of the event that were listed in DR 97-0975 were written communication, work practices, and resource management. The licensee attributed the lack of a sign off for the procedural step which controlled the event and this was the first time the crew had performed the activity as contributors to the event. Although 0-MCM-1150-01 Step

6.11.6 had a sign off blank, the proposed corrective actions were to add a sign off to its substep, Step 6.11.6.c, and revise Figure 13 of the procedure to show additional detail. DR 97-0795 was closed on the basis that 0-MCM-1150-01 had been revised to include the sign off for Step 6.11.6.c and the figure revision was being tracked by Procedure Manager Tracking Number, MEFB 97-0031 and the revision would be completed prior to the Unit 2 RFO. The inspectors discussed their inability to find the procedure revision with the licensee. The licensee provided the inspectors with a one time only procedure action request which added the sign off step to Step 6.11.6.c and a change to Section 6.9. This action changed the procedure for work during the RFO, but did not revise the procedure.

The proposed corrective actions for DR 97-0782 were to add the sign off as described above, add a "Caution" so that RTV is not applied under the standoffs, and add a step after Step 6.9.7 to check the manway fastener torque. The DR was closed out by stating that the MEFB-97-0031 had been issued to track the procedure revision, which will incorporate these (and other) changes. Both DRs were approved for closure by the Station Nuclear Safety and Operating Committee (SNSOC) on April 10, 1997.

On April 22, 1997, the inspectors requested a copy of Procedure 0-MCM-1150-01 from the licensee's Document Control and received 0-MCM-1150-01, Revision 4. The inspectors reviewed 0-MCM-1150-01, Revision 4, and did not observe a sign off for Step 6.11.6.c as indicated by the closure document. Step 6.11.6.c states, "Apply a small bead of RTV sealant along the entire circumference of the inner J-Seal where the seal contacts the reactor flange. (The bead should be at least 1/8 inch thick.)" The inspectors consider that this step is very clear as to what is required when applying RTV to the inner J-Seal. MEFB-97-0031 was also reviewed and the inspectors noted that it only states under comments that the procedure needs to be revised after the current RFO. It references DR 97-0795 but there is no reference to the proposed procedure revisions contained in DR 97-0782.

c. Conclusions

Maintenance personnel failed to follow the procedure in that they did not place RTV along the entire circumference of the inner J-Seal resulting in the cavity seal leak during post installation testing. This is a Violation (50-280/97003-02) of TS 6.4.D. The inspectors consider that work practice is the only causal factor described in DR 97-0795 to be valid. The procedure is clear and explicit. The inspectors concluded that the response to DR 97-0795 should have been more explicit in that it did not detail the work practice/failure to follow procedure issue. The proposed corrective actions involving revising the procedure are enhancements and will likely not prevent recurrence. The inspectors discussed this with plant management and plant management stated that they would review the issue.

M1.2 Replacement of Service Water Valve 1-SW-MOV-105B

a. Inspection Scope (62707)

The inspectors monitored maintenance activities involving the replacement of service water valve 1-SW-MOV-105B.

b. Observations and Findings

On April 12, the inspectors observed portions of the replacement of service water valve 1-SW-MOV-105B. The work was being performed in accordance with Work Order (WO) 00363165-03 and Design Change 97-016. The valve was replaced because it would not satisfactorily pass a local leak rate test. In this instance, a valve of the type previously installed was no longer available, thereby requiring a new type valve to be installed in accordance with an approved design change (97-016). All work observed by the inspectors was performed properly and in accordance with the specified work instructions. The inspectors reviewed the associated documentation and found it satisfactory with one minor exception. Specifically, neither the design change nor the WO provided detailed instructions for the installation of a flange insulation kit. This kit was required to be installed to eliminate any galvanic corrosion concerns due to the dissimilar metals of the new valve and the existing piping. The inspectors questioned the maintenance personnel performing the task about the methodology for installation of the insulation kit. The maintenance personnel indicated that they had received appropriate oral instructions from their supervision and engineering personnel concerning the installation of the insulation kit and were cognizant of the proper installation procedure. The inspectors discussed with plant management that providing more detailed installation instructions would enhance future tasks of this type.

c. Conclusions

The work performed to install 1-SW-MOV-105B was performed properly and in accordance with the specified work instructions. Providing more detailed instructions in the design change and WO was discussed with plant management as a potential enhancement for future tasks of this type.

M1.3 Unit 1 Outage Activities

a. Inspection Scope (61726, 62707)

The inspectors reviewed a number of activities during the Unit 1 RFO.

b. Observations and Finding

1. Unit 1 Safety Injection Accumulator 1C, Change In Boron Concentration

The licensee observed that the boron concentration in Safety Injection (SI) accumulator 1C was decreasing while the level remained constant. The accumulator is connected to the cold leg of the C loop by a 12-inch line. The line goes from the cold leg to the accumulator through two check valves (1-SI-147/145) and an open motor operated gate valve (1-SI-MOV-1865C). The check valves are oriented to allow flow from the accumulator to the reactor coolant cold leg. The system engineer theorized that check valve 1-SI-147 leaked by allowing the 2200° F reactor coolant to flow to the accumulator. Thermal mixing caused the reactor coolant with a lower boron concentration to dilute the coolant in the accumulator. The system engineer believed the constant level was the result of valve 1-SI-MOV-1865C packing leakage being equal to the 1-SI-147 inleakage.

The licensee replaced the seat ring in 1-SI-147 and this was accomplished by WO 00328809-01. WO 00359031-01 was issued to repack valve 1-SI-MOV-1865C. The inspectors noted during their WO review that both check valves were overhauled on September 23, 1995, because of boron dilution in the C accumulator. In addition, 1-SI-MOV-1865C was previously repacked on December 9, 1994. The inspectors verified that the licensee completed their corrective actions for the boron dilution in the C accumulator. The effectiveness of the corrective actions can not be determined until the unit has been at power.

2. Primary Power Operated Relief Valve (PORV) Maintenance

During the last Unit 1 operating cycle, primary PORV 1-RC-PCV-1455C was isolated because its associated block valve was shut due to leakage through the PORV. To correct this problem, the licensee performed a complete rebuild of the valve. This included replacement of the valve's plug, cage and stem. The inspectors reviewed the associated work documentation and considered that the maintenance performed was satisfactory.

3. Pressurizer Spray Valve Maintenance

During the last Unit 1 operating cycle, pressurizer spray valve 1-RC-PCV-1455B was isolated due to faulty operation and seat leakage. During the current Unit 1 outage, the valve body and internals were replaced. The inspectors reviewed the associated work documentation and considered that the maintenance performed was satisfactory.

4. Pressurizer Instrumentation Nozzle Visual Inspections

During the previous Unit 1 RFO, an inspection of the pressurizer instrumentation nozzles revealed evidence of leakage. The nozzles in question were removed and replaced. This matter was reported to the NRC in LER 280/95007-00. An action to prevent recurrence for this event was to perform a visual inspection of the nozzles during the unit's next RFO. The licensee performed a visual inspection of the Unit 1 pressurizer instrumentation nozzles and noted no leakage. The inspectors reviewed the visual examination report and considered that the licensee's inspection was satisfactory.

c. Conclusions

The inspectors determined that the licensee performed the appropriate actions to correct a number of longstanding equipment problems. The effectiveness of these activities will be determined during the next operating cycle.

M2 **Maintenance and Material Condition of Facilities and Equipment**

M2.1 Observation of Unit 1 ISI Work Activities

a. Inspection Scope (73753)

This is the first outage, of the second inspection period, of the third ISI interval. The applicable code for Unit 1, for the third ISI interval was the American Society of Mechanical Engineers (ASME) Code Section XI, 1989 Edition, no Addenda. The inspectors reviewed documentation and observed work activities to determine whether the ISI activities were performed in accordance with TS, the applicable ASME Code, and/or requirements imposed by NRC/industry initiatives.

b. Observations and Findings

The inspectors reviewed the Inservice Inspection (ISI) outage examination plan and the component examination schedule for the current inspection period. The reviews were performed to determine if changes to the component examination schedule for the current inspection period had been properly documented. Certification records for examiners performing ISI examinations this outage were reviewed. Virginia Power Procedure No. NDE-UT-601, "Ultrasonic Examination of Piping Welds," Revision 0, was also reviewed for technical content.

Ultrasonic examination of reactor coolant welds Nos. 3-01DM and 3-02 were observed. These ASME Code welds were four-inches in diameter and were located on top of the pressurizer. Although the examinations were conducted satisfactorily, one discrepancy was noted by the inspectors. The ISI drawing for the upstream elbow weld on the elbow (Pressurizer Line No. 4"-RC-34-1502), which was attached to the reducer on the pressurizer nozzle, was not depicted on ISI Drawing No. 11448-WMKS-

0124A1-1. The licensee subsequently stated that, when insulation was removed, it was not unusual to find a weld that was previously not identified in the program. However, the program contained an adequate surplus of welds, which were examined in the event that additional welds were identified during inspection activities. The licensee also stated that as welds were found, the ISI drawings were revised to depict the locations of the new welds.

In addition to the above, the inspectors also observed two ultrasonic examinations (Welds Nos. 1-02 and 1-03) on the 14-inch diameter feedwater piping running to steam generator A and one ultrasonic examination (Weld No. 1-01) on the 16-inch diameter feedwater piping running to steam generator B. The feedwater piping examination was performed in accordance with the requirements of NRC Bulletin No. 79-13.

c. Conclusions

The ISI period plan, personnel certifications, weld examinations, and the ultrasonic examination procedure were in accordance with Code requirements. One discrepancy was noted, in that, the drawing for the upstream elbow weld on Pressurizer Line No. 4"-RC-34-1502 (weld adjacent to Weld No. 3-02) was not depicted on the ISI reactor coolant isometric sketch. The licensee took actions to have the ISI drawing revised.

M2.2 Observation of Unit 1 Steam Generator A Eddy Current Data Analysis Activities

a. Inspection Scope (73753)

The inspectors reviewed the Surry Power Station Unit's 1 & 2 Steam Generator Monitoring and Inspection Program Plan, the Surry Site Specific Eddy Current Data Analysis Guidelines (Procedure No. SRY-SGPMs-002.2, Revision 0), the Westinghouse Electric Corporation Nuclear Services Division Steam Generator Primary Maintenance Services Data Analysis Technique Procedure No. DAT-GYD-001, Revision 7, and personnel certification records for all of the Westinghouse examiners and analysts. In addition, tube evaluation and data analyst activities were inspected.

b. Observations and Findings

The licensee's single steam generator inspection program was initiated on Unit 1 in 1994. During each outage, 100 percent bobbin coil inspections of all open tubes in one steam generator are examined. In addition, a 20 percent sample of hot leg tube sheet transitions in one steam generator are examined each outage using a Motor Rotating Pancake Coil (MRPC). Based on this program, 100 percent of all steam generator tubes are bobbin coil examined within a rolling 60 month schedule. Under ASME Section XI, 1989 Edition, the extent and frequency of examination is governed by the plant TSs. Surry Unit 1 TS, Section 4.19.C requires 3 percent of all tubes be examined (301 tubes); however, 3336 tubes were bobbin coil examined in A Steam Generator (100 percent

of all tubes in A). In addition, 669 hot leg tube sheet transitions (20 percent sample) will be MRPC examined this outage. The inspectors' review of documentation delineated in the scope paragraph above and observation of the online evaluation process revealed that the approved data analysis guidelines were being followed; the data analysts were very knowledgeable of the requirements and operation of their equipment; and the 100 percent bobbin coil examinations were complete with no reportable pluggable indications identified at this point in the outage examinations.

c. Conclusion

The review of procedures, personnel certifications, and evaluation of recorded eddy current data for tubes in the A steam generator revealed that the Westinghouse personnel (including their contractors) were very knowledgeable of the eddy current examination and the data analysis process.

M2.3 Unit 1 Flow Accelerated Corrosion (FAC) Program

a. Inspection Scope (49001)

The licensee has approximately 5000 components in the Unit 1 FAC program. Approximately 110 to 121 of these components are scheduled each outage to be examined. The inspectors held discussions with the licensee's erosion/corrosion engineers to determine the scope of FAC examinations scheduled for this outage, the condition of the plant piping as revealed by inspection; the extent of pipe replacement required; and whether proper examination expansion was performed when defective components were found.

b. Observations and Findings

The licensee's initial sample of components scheduled for ultrasonic examination this outage was 113. The licensee had also planned to replace 22 components without further examination, based on corrosion growth rates confirmed last outage. However, discussions with cognizant personnel revealed that ultrasonic thickness examinations had identified 20 additional components that had to be replaced. The licensee would now have to replace 48 total components this outage. In addition, the sample of components was expanded to 140 total components. The high rejection rate of components in relationship to the average sample of components scheduled for examination during this outage concerned the inspectors. Therefore, discussions were held with cognizant licensee personnel to determine the results of previous outage operations. This review revealed that a significant number of components had been repaired or replaced as the result of inspection for Unit 1 in both the 1994 (13) and 1995 (21) outages. However, the inspectors found that the licensee has not experienced any recent leaks and no sealant cans were installed on either units. The inspectors also verified a portion of the licensee's component expansion inspections and found that they had been conducted properly.

During a meeting with senior management, the inspectors expressed concern over the high component rejection rate. The inspectors were informed by senior management that they were also concerned over the number of components requiring replacement.

Therefore, as soon as the examinations of components were completed, and the total replacements determined, Virginia Power would review this problem in detail, and determine an appropriate course of action. The actions to be taken would be sent to the inspectors for review. DR S-97-0895 was written by the licensee to address these issues.

On April 4, 1997, a response was provided to the inspectors in Region II. This response addressed the high rejection level issue raised by the inspectors. The response also addressed wear-rates seen on the feedwater components, which were somewhat higher than predicted either by previous evaluation or by the CHECWORKS modeling; and that conservatism currently utilized in the prediction of component life may not be sufficient enough to consistently prevent the violation of code minimum wall thickness. As a result of these concerns, an action plan was implemented by the licensee. On April 9, 1997, the licensee clarified the engineering positions relative to inspection scope expansion and the safety of the unit's piping systems in light of the recent FAC findings. On April 10, 1997, a conference call was held with representatives from Virginia Power, at both the Surry Power Station and the Innsbrook Technical Center, and the NRC to discuss the licensee's submittal and their action plans. The NRC agreed that the licensee was taking appropriate action at this time.

As part of their action plan for DR S-97-0895, the licensee had contacted the Electric Power Research Institute (EPRI) to conduct a site visit (tentatively May 5, 1997) to perform a technical engineering review of the Virginia Power Secondary Piping Component Inspection Program. CHECWORKS databases, system models and outage data have already been transmitted to EPRI for review. NRC personnel considered this was a good action taken by the licensee. However, the licensee was notified that when the EPRI assessment of the Unit 1 FAC program was completed, Region II will conduct an inspection at the Innsbrook Technical Center to review the licensee's progress on each of the action items addressed in the response to DR S-97-0895.

c. Conclusions

Virginia Power Company has approximately 5000 components in the Unit 1 FAC program. Approximately 110 to 121 of these components are scheduled each outage to be examined. A concern was expressed when high component replacement rates were experienced from the small sample of components examined. The licensee issued DR S-97-0895 to address FAC concerns. Licensee actions planned in response to this deviation were considered good.

III. Engineering

E1 Conduct of Engineering

E1.1 RFO Modifications to Correct Long Standing Issues

a. Inspection Scope (37551)

The inspectors reviewed two modifications which addressed longstanding issues.

b. Observations and Finding

1. Unit 1 Steam Generator Channel Head Drain Replacement

The licensee had experienced leakage from the Unit 2 steam generator channel head drain. The corrective action was to remove the drain line at the steam generator and replace it with a stainless steel plug. Engineering developed Design Change Package (DCP) 95-046, "SG Channel Head Drain Isolation," to remove the drain lines from the Unit 1 steam generators. The inspectors reviewed DCP 95-046 including the safety review and the proposed changes to UFSAR, Section 4.2.2.3.2.3. The work was controlled by WOs 00337078-01, 02, and 03 for steam generators 1A, 1B, and 1C respectively. The inspectors reviewed completed WO 00337078-03 and procedure 0-MCM-1801-01, "Piping, Components Repair and Replacement," Revision 4. The inspectors verified that applicable sections of the procedure had been signed off and the WO closed out.

2. Source Range Nuclear Instrumentation (NI) Detector Cabling Replacement

The cables for both the intermediate and source range NI detectors were replaced to reduce extraneous "noise" in the detectors. The change was controlled by DCP 96-007. On March 12, 1997, the N-31 detector was declared operable at 7:45 a.m., after completion of post maintenance testing. However, the Raychem protector had not been applied. At 12:30 p.m., a technician disconnected the cable as he believed it would be easier to install the Raychem with the cable disconnected. The control room was unaware that the N-31 cable would be disconnected. The technicians notified the control room of their actions and the detector was declared inoperable. The Raychem was installed and the N-31 detector was declared operable at 1:09 p.m., following satisfactory performance of 1-PT-1.1, "NIS Trip Channel Test Prior to Startup." The technicians did not install the Raychem prior to acceptance testing in the event that problems occurred during testing and the Raychem had to be removed. The licensee determined that the technician had not been briefed that the detector was energized. DR 97-0709 was issued to follow the event.

The inspectors reviewed DCP 96-007 and noted that the modification was performed by Westinghouse. Westinghouse procedures were used to control the cable changeout. The inspectors did not find any cautions or directions relating to the sequence of installing the Raychem. The inspectors concluded that the event was caused by poor communications.

c. Conclusions

The modification activities reviewed by the inspectors during the RFO should correct two longstanding equipment deficiencies.

E1.2 Unit 1 Letdown Line Orifice and Piping Replacement

a. Inspection Scope (37551)

The inspectors reviewed the licensee's actions related to the replacement of the Unit 1 letdown line piping and orifices.

b. Observations and Findings

On March 15, the licensee performed radiographic examinations on the Unit 1 letdown orifices to check for a similar erosion condition previously seen on the B Unit 2 letdown orifice. Vibration testing of the Unit 1 letdown lines performed at hot shutdown exhibited values higher than those normally expected, but less than allowable. The results of the Unit 1 exam were as follows;

- A 45 gpm Orifice: This orifice exhibited the most extensive deterioration with its nominal 0.212 inch diameter being eroded to an inside diameter of approximately one-inch over the last five inches of the orifice. A microscopic examination of the sectioned orifice indicated the damage was caused by cavitation.
- B 60 gpm Orifice: This orifice exhibited only minor erosion.
- C 60 gpm Orifice: This orifice exhibited deterioration with its nominal 0.242 inch diameter being eroded to an inside diameter of approximately one-half inch over the last one and one-half inches of the orifice.

Based on the results of these examinations, the licensee replaced all three orifices during the ongoing Unit 1 RFO. In addition, the licensee replaced the piping downstream of the orifices and inspected the letdown isolation valves. The piping was fabricated with butt welds in lieu of the existing socket welds.

The inspectors monitored the piping replacement activities. The licensee has theorized that the erosion in the orifices in Unit 2 led to increased vibration and ultimately cracking of the lines. Although Unit 1 has not experienced any letdown line cracking like those seen on

Unit 2, the licensee's action to replace the orifices and piping were prudent.

c. Conclusions

Based on the deterioration seen in the Unit 1 letdown orifices following radiographic examination, the licensee prudently replaced the orifices and associated downstream piping during the 1997 Unit 1 RFO.

E8 Miscellaneous Engineering Issues (92902)

- E8.1 (Open) LER 50-280/97001-00: shutdown due to steam drain line weld leak. This LER discussed the January 24, 1997, Unit 1 shutdown due to a pinhole leak on a main steam drain line in the main steam valve house. During the unit shutdown, both source range NIs failed after energization. Section 4 (Immediate Corrective Actions) of this report stated that the plant was borated to the cold shutdown condition. The inspectors questioned the accuracy of this statement. The unit was borated to hot shutdown conditions and shutdown margin was verified as required by TSs. Licensee management made a conscious decision not to borate to cold shutdown conditions during the event. This item was discussed with plant licensing personnel and plant management. The licensee agreed that the statement was not accurate and initiated a revision to the LER to correct the matter. The inspectors identified an example of an inaccurate LER submittal in the previous IR (50-280, 281/97002). This item is identified as Violation 50-280/97003-03. The licensee incorporated corrective actions for this violation in their response to the previous violation. This LER will remain open pending revision.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Occupational Radiation Exposure Control Program

a. Inspection Scope (83750)

The inspectors reviewed implementation of selected elements of the licensee's radiation protection program during a segment of the Unit 1 RFO. The review included observation of radiological protection activities including pre-work briefings, personnel exposure monitoring, radiological postings, and verification of posted radiation dose rates and contamination levels within the Radiologically Controlled Area (RCA). Those activities were evaluated for consistency with the programmatic requirements, personnel monitoring requirements, occupational dose limits, radiological posting requirements, and survey requirements specified in Subparts B, C, F, G, and J of 10 CFR 20.

b. Observations and Findings

The inspectors conducted frequent tours of the RCA to observe radiation protection activities and practices. Personnel preparing for routine entries into the RCA were observed being briefed on the radiological conditions in the areas to be entered. The briefings were given by radiation control personnel before access was granted and covered the dosimetry and the protective clothing and equipment required by the Radiation Work Permit (RWP) for the entry. The administrative limits for the allowed dose and dose rate for the entry were emphasized during the briefings. The briefings provided thorough descriptions of the existing dose rates which could be encountered during the entry. The inspectors determined that personnel entering the RCA were adequately briefed on the radiological hazards which could be encountered while in the RCA and the radiological protective measures required to be taken during the entry.

The inspectors observed the use of personal radiation exposure monitoring devices by personnel entering and exiting the RCA. Thermoluminescent Dosimeters (TLDs) were used as the primary device for monitoring personnel radiation exposure. In addition, Digital Alarming Dosimeters (DADs) were used for monitoring the accumulated dose and the encountered dose rates during each RCA entry. The DADs were set to alarm at administrative limits established for the specific RWP under which the RCA entry was being made. As the individuals exited the RCA the accumulated dose and encountered dose rate information was transferred from the DADs to the Personnel Radiation Exposure Management System (PERMS) data base in order to track individual exposures. During tours of the RCA the inspectors noted that the required dosimetry was being properly worn by personnel when entering and while in the RCA. The inspectors also noted that personnel exiting the RCA routinely surveyed themselves for contamination using a Personal Contamination Monitor (PCM).

The inspectors discussed with the licensee the special procedures implemented for releasing personnel from the RCA when xenon contamination was suspected. The licensee provided the inspectors with the following general description of the release process. Routine decontamination procedures and release criteria were followed if an individual alarmed the PCM at the RCA exit portal and the contamination was determined to have been localized. If the PCM alarm was determined to have been caused by generally uniformly distributed activity, then additional surveys were performed to determine which radionuclides were present. If the activity was found to be other than xenon, such as cesium or cobalt, then additional decontamination was performed. If the activity was found to be xenon, the individual was surveyed with a hand frisker to assure that the routine release criterion of 1000 dpm was met. A release permit was then provided to the individual in the event that the more sensitive portal monitor at the protected area exit point were to alarm. Overall, the routine and special procedures assured that any individual who alarmed the PCM was required to meet the routine release criteria established for surveys by a hand frisker. The

licensee indicated that the special procedures were in effect for less than two weeks due to the short half-life of xenon.

The inspectors reviewed As Low As Reasonably Achievable (ALARA) program details, implementation, and goals for the Unit 1 RFO. Based on the scheduled activities, daily and cumulative exposure projections were established. Individual exposures, based on data from DADs and PERMS, were summarized by RWPs on a daily basis and allocated to the various organizational departments. Daily reports of the collective and departmental exposures, along with their respective projected goals were issued for monitoring purposes. Plots of daily and cumulative exposure vs. their respective projections were also distributed daily. The inspectors noted that daily and cumulative projections were exceeded early in the outage but by day 29 of the scheduled 39 day outage the cumulative exposure was below the projected value.

During tours of the RCA the inspectors noted that general areas and individual rooms were properly posted for radiological conditions. Posted survey maps were used to indicate dose rates and contamination levels at specific locations within rooms. At the inspectors' request, a licensee Health Physics staff member performed dose rate and contamination surveys in several rooms and locations. The inspectors verified that the survey instrument readings were consistent with the dose rates and contamination levels recorded on the posted survey maps.

The licensee provided for the inspectors' review a copy of the Five-Year Exposure and Low-Level Radwaste Management Plan. The inspectors noted that the plan consisted of the following four objectives: increase and expand efforts in innovative technology application; continue source term reduction efforts; continue waste generation reduction efforts; and continue high worker awareness and improved job and outage planning. A list of activities and implementing schedules for achieving those objectives was also delineated in the plan.

c. Conclusions

Based on the above reviews, the inspectors concluded that the licensee was properly monitoring and controlling personnel radiation exposure and posting area radiological conditions in accordance with 10 CFR Part 20.

R1.2 Radioactive Effluent Monitoring Instrumentation

a. Inspection Scope (84750)

The inspectors reviewed licensee's procedures and records pertaining to surveillances and alarm setpoints for selected radioactive effluent monitors. The surveillance procedures and established alarm setpoints were evaluated for consistency with the operational and surveillance requirements for demonstrating the operability of the monitors. Those requirements were specified in Sections 6.2.2 and 6.3.2 and Attachments 3 and 16 of VPAP-2103, "Offsite Dose Calculation Manual (ODCM)."

b. Observations and Findings

The inspectors toured the Control Room and relevant areas of the plant with a licensee representative to determine the operational status for the following effluent monitors:

RM-RRM-131	Radwaste Facility Liquid Effluent Line
1-GW-RM-102	Process Vent Noble Gas Activity Monitor
1-VG-RM-110	Ventilation Vent Noble Gas Activity Monitor
RRM-101	Radwaste Facility Vent Noble Gas Activity Monitor

The above monitors were found to be well maintained and operable at the time of the tours.

The inspectors reviewed the 14 procedures related to channel checks, source checks, channel calibrations, channel functional tests, and alarm setpoints for the above listed monitors. The inspectors determined that the procedures included provisions for performing the required surveillances in accordance with the relevant sections of the ODCM and at the specified frequencies. The inspectors also reviewed the most recently completed surveillances for the above listed monitors. Those records indicated that the surveillances were current and had been performed in accordance with their applicable procedures. The inspectors also verified that the alarm setpoints for the above listed monitors were consistent with procedure HP-3010.040 and ODCM requirements. The licensee indicated that effluent monitor percent availability was not routinely tabulated, therefore, the inspectors reviewed the licensee's 1996 maintenance history records for the above listed monitors. Those records indicated that the monitors were very seldom out of service except for scheduled preventive maintenance and surveillance testing. The inspectors also discussed the licensee's Radiation Monitoring Upgrade Program with the cognizant Project Engineer. The project included installation of new digital display/controllers in the Control Room, installation of new detectors, and wiring upgrades. The licensee indicated that the project was 80 percent complete for Unit 1, 100 percent complete for Unit 2, and 50 percent complete for common systems. The planned completion date for the project is year end 1997. During a tour of the Control Room the licensee demonstrated for the inspectors the enhanced capabilities of the new digital display/controllers. The inspectors determined that the radiation monitor upgrade project was a significant program improvement.

c. Conclusions

Based on the above reviews and observations, it was concluded that the licensee was maintaining radioactive effluent monitoring instrumentation in an operable condition and performing the required surveillances to demonstrate their operability.

R1.3 Meteorological Monitoring Program

a. Inspection Scope (84750)

The inspectors evaluated implementation of the licensee's onsite meteorological measurements program for consistency with the program description contained in Section 2.2.1.2 of the UFSAR.

b. Observations and Findings

The inspectors reviewed meteorological surveillance procedures and determined that they included provisions for performing daily channel checks and semiannual channel calibrations. The inspectors also reviewed the records for the most recent instrument calibrations for wind speed, wind direction, and air temperature which were performed during November and December 1996. Those records indicated that the calibrations were current and had been performed in accordance with the applicable procedures. During a tour of the Control Room, licensee personnel displayed on a monitor the computerized log of the daily channel checks performed for the previous 2 days. The inspectors also noted that the meteorological monitoring instrumentation was operable at the time of the tour.

c. Conclusions

Based on the above reviews and observations, the inspectors concluded that the onsite meteorological measurements program was implemented in accordance with the UFSAR.

R1.4 Control Room Emergency Ventilation System

a. Inspection Scope (84750)

The inspectors reviewed the licensee's procedures and records for the surveillances required to demonstrate operability of the Control Room Emergency Ventilation System (CREVS). Those procedures and records were evaluated for consistency with the operational and surveillance requirements delineated in TSs 3.23 and 4.20.

b. Observations and Findings

The inspectors toured the Turbine Building, Control Room, Emergency Switchgear and Relay Room, and Mechanical Equipment Rooms in which the CREVSs were located. The licensee's cognizant system engineer accompanied the inspectors on the tours, during which the major components of the systems were located and identified. The emergency ventilation systems included four independent units consisting of fans, dampers, pre-filters, High Efficiency Particulate Air (HEPA) filters, and charcoal adsorber filter beds. The inspectors verified that the air flow paths and arrangement of the system components within those paths were consistent with the system diagram (Figure 9.13-3) referenced in Section 9.13.3.6 of the UFSAR. The inspectors observed that the

components and associated ductwork were well maintained structurally and that there was no physical deterioration of the equipment or ductwork sealants.

The inspectors reviewed selected ventilation system surveillance procedures and determined they included provisions for performing functional tests, filter leak testing, air flow measurements, differential pressure measurements, and charcoal adsorption efficiency testing. The surveillance frequency and acceptance criteria for the test results specified in those procedures were consistent with the TS requirements. Review of selected records of those tests, generally the most recently completed, indicated that they had been performed in accordance with the testing procedures and that the acceptance criteria had been met.

c. Conclusions

Based on the above reviews and observations, the inspectors concluded that the licensee was maintaining the CREVS in an operable condition and they were performing the required surveillances to demonstrate operability of the system.

S1 Conduct of Security and Safeguards Activities (71750)

On numerous occasions during the inspection period, the inspectors performed walkdowns of the protected area perimeter to assess security and general barrier conditions. No deficiencies were noted and the inspectors concluded that security posts were properly manned and that the perimeter barrier's material condition was properly maintained.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on April 25 and May 14, 1997. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

R. Blount, Superintendent, Maintenance
 D. Christian, Station Manager
 M. Crist, Superintendent, Operations
 J. McCarthy, Assistant Station Manager, Operations & Maintenance
 B. Shriver, Assistant Station Manager, Nuclear Safety & Licensing
 T. Sowers, Superintendent, Engineering
 B. Stanley, Director, Nuclear Oversight
 W. Thorton, Superintendent, Radiological Protection

NRC

N. Diaz, Commissioner, Nuclear Regulatory Commission
 L. Reyes, Regional Administrator, Region II

INSPECTION PROCEDURES USED

IP 37551: Onsite Engineering
 IP 40500: Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
 IP 49001: Inspection of Erosion/Corrosion Monitoring Programs
 IP 61726: Surveillance Observation
 IP 62707: Maintenance Observation
 IP 71707: Plant Operations
 IP 71750: Plant Support Activities
 IP 73753: Inservice Inspection
 IP 83750: Occupational Exposure
 IP 84750: Radioactive Waste Treatment and Effluent and Environmental Monitoring

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-280/97003-01	VIO	Loss of refueling containment integrity (Section 01.2).
50-280/97003-02	VIO	Failure to follow maintenance procedure (Section M1.1).
50-280/97003-03	VIO	Failure to meet the requirements of 10 CFR 50.9 (a) for LER 50-280/97001-00 (Section E8.1).

Closed

50-281/95001-00	LER	Pressurizer heatup exceeded TS limit due to lack of procedural control (Section 08.1).
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50-281/95-06-02

VIO

Pressurizer heatup rate exceeded TS limits of 100° F/hour (Section 08.2).

50-280/97006-00

LER

Loss of refueling integrity due to inadequate containment closure process (Section 08.3).

Discussed

50-280/97001-00

LER

Shutdown due to steam drain line weld crack (Section E8.1).