VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

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VIRGINIA ELECTRIC AND POWER COMPANY (DOMINION)
NORTH ANNA POWER STATION UNITS 1 & 2
RESPONSE TO NRC INSPECTION REPORT NOS. 05000338,339/2005004

Dominion has reviewed Inspection Report Nos. 05000338,339/2005004, dated October 28, 2005. Although Dominion does not disagree with the characterization of the identified items as findings in the inspection report, we do disagree with the NRC's conclusions that the issues associated with flood protection measures and main turbine auto stop interface valve oil leakage contain aspects relating to the cross-cutting area of problem identification and resolution. In addition, Dominion disagrees with the conclusion that the issues associated with the breaker 2-QS-P-1B and Solid State Protection System channel testing contain aspects relating to the cross-cutting area of human performance. The basis for these conclusions is discussed in detail in the attachment.

The inspection report also identifies a minor violation associated with inadequate corrective actions for the Unit 1 Turbine Driven Auxiliary Feed Water pump. Dominion disagrees that the conclusions reached regarding the use of Item Equivalency Evaluation Review process constitutes a minor violation. The basis for this conclusion is also described in detail in the attachment.

If you have any questions or require additional information, please contact Mr. Page A. Kemp at (540) 894-2295.

Very truly yours,

Eugene S. Grecheck
Vice President - Nuclear Support Services

Attachment

Commitments made in this letter: None

IE01

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Attachment

Dominion Response to NRC Findings from Inspection Report 50-338,339/2005004

Virginia Electric and Power Company
(Dominion)
North Anna Power Station
Units 1 and 2

Dominion Response to NRC Findings From Inspection Report 50-338,339/2005004

I Flood Protection Finding

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors reviewed internal flood protection measures for the Unit 1 and 2 air conditioning chiller rooms (ACCRs) and adjacent air conditioning fan rooms (ACFRs). Flooding in the ACCRs and ACFRs could impact risk-significant components in the instrument rack rooms adjacent to the ACFRs if flood mitigation features were degraded. ACCR and ACFR protection features were observed to verify that they were installed and maintained consistent with the plant design basis. The inspectors reviewed the instrumentation and associated alarms for the rooms above to verify that the instrumentation was periodically calibrated and that the respective alarms were appropriately integrated into plant procedures. The inspectors also reviewed licensee instructions in the event of severe flooding and evaluated the availability of systems, structures and components (SSCs) for safe shutdown under worst case water levels. Documents reviewed are listed in the Attachment.

b. Findings

Inadequate Corrective Action Results in Safeguards Instrument Rack Room Flood Problem

Introduction: The inspectors identified a self-revealing violation associated with inadequate corrective action. Back flow preventers were not installed in floor drains that resulted in a flood potential for the Unit 1 and 2 Safeguards Instrument Rack Rooms. The safety significance is under evaluation and thus the item is classified as an unresolved item.

Discussion: On July 9, 2005, back flush of control room chiller service strainers 2-HV-S-1A and 1B as directed by engineering transmittal, ET N-05-0034, "Operability of 2-HV-P-22C, Service Water Pump for 2-HV-E-4C," was performed in the Unit 2 ACCR. During this work activity, the licensee observed water discharging from the floor drains in the adjacent ACFR, and initiated Plant Issue N-2005-2565 to evaluate the absence of back-flow preventers in the floor drains. The licensee initiated a flood watch, declared the flood walls between the ACCR and adjacent ACFR on Units 1 and 2 inoperable and entered a Yellow 6 day maintenance rule risk condition based on unavailability of the flood walls to perform their function. The respective ACFR on both units are adjacent and open to the safeguards instrument rack rooms, which contain the solid state protection system (SSPS) and process instrumentation and are at a 2 feet lower elevation. Each instrument rack room has a sump with two pumps rated at 40

gpm each. On Unit 2 the sump pumps' discharge line is hard-piped directly to the ACCR sump. However, on Unit 1 the sump pumps' discharge line is routed to a drain funnel interconnected to the floor drain system of the adjacent ACFR. The licensee determined that this funnel did not have a back-flow preventer installed and initiated Plant Issue N-2005-2597. A subsequent calculation, ME-0782, was performed by the licensee to evaluate the consequences of a service water line break in either the Unit 1 or 2 ACCRs. The calculation concluded that the peak flow rate from the Units 1 and 2 ACCRs to adjacent ACFRs via the floor drain piping was 182.9 gpm and 169.4 gpm respectively.

The inspectors reviewed the licensee's corrective action database and determined that on October 15, 2004, Plant Issue N-2004-4554 was initiated due to water discharge from a capped floor drain outside of the ACCR. An "other" evaluation was assigned to engineering to review this condition for impact on the flood protection assumed for the ACCR and connecting areas as applicable. This evaluation did not identify and correct the absence of back-flow preventers in the adjacent ACFR floor drains. The inspectors also identified that Plant Issue N-1999-3405, which documented operational experience from Three Mile Island regarding check valves missing from floor drains and the impact on flood protection, did not result in the identification and correction of this problem. The inspectors concluded that the inadequate corrective actions for Plant Issue N-2004-4554 is contrary to the requirements of 10 CFR 50, Appendix B, Criterion XVI, which requires that the establishment of measures to assure conditions adverse to quality are promptly identified and corrected.

Analysis: The inspectors determined that the finding had a credible impact on safety based on the potential for flooding to impact both trains of SSPS cabinets used for engineered safeguards. The inspectors referenced IMC 0612 and determined that if left uncorrected this finding would result in a more significant safety concern and is consequently more than minor. Based on a review of IMC 0609 for the SDP, the inspectors determined the finding would require a Phase III evaluation due to the loss or degradation of equipment specifically designed to mitigate a flooding event and the impact on two trains of a safety system. This finding is an URI pending completion of the significance determination assessment and contains aspects relating to cross-cutting area of problem identification and resolution.

Enforcement: 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, requires the establishment of measures to assure conditions adverse to quality are promptly identified and corrected. Contrary to the above, prompt identification and correction of deficiencies relating to Plant Issue N-2004-4554 failed to identify and correct the absence of back-flow preventers in the Unit 1 and 2 ACFRs. This violation is characterized as an URI pending significance determination, and is identified as URI 05000338,339/2005004-02, Inadequate Corrective Action Results in Safeguards Instrument Rack Room Flood Problem. This finding is in the licensee's CAP as Plant Issue N-2005-2565.

Dominion Response

As noted above, in October 15, 2004, Plant Issue (PI) N-2004-4554 was initiated due to water leakage from a capped floor drain outside of the ACCR. This leakage was in the ACCR sump pump discharge line in the turbine building basement. An evaluation was performed. It was determined that due to the size of the leak and its location in the turbine building basement it was not credible for this leaking capped floor drain to adversely affect the operability of any equipment in the chiller room and connecting areas.

The leak in the basement of the turbine building is isolated from the ACCR by a floodwall and associated piping of the sump pump. There is no direct interconnected piping that can circumvent the flood barrier. In the 2004 event, leakage would have been required to overflow the floodwall before affecting safety-related systems. The evaluation of the 2004 event was directed at the potential for an overflow condition and established that the flood control design could not credibly be breeched. Therefore, neither the leakage phenomenon nor the design features of prevention in the 2004 leakage event have any relationship with the 2005 event, which was associated with interconnected systems and back-flow prevention to preclude flooding in the ACFR.

Based on the nature of the flooding event and the design features, it is unrealistic to assume the 2004 evaluation should have addressed back flow preventers for areas that would not be affected by leakage in the turbine basement.

In contrast, on June 9, 2005, during a flush of the control room chiller service water strainers, water was noted to be discharging from the drains in the adjacent ACFR. Actions were immediately initiated to evaluate and identify the source of the water and subsequent corrective actions. This was captured in the Corrective Action Program (CAP) as PI N-2005-2565. The evaluation of the condition noted in the PI resulted in installation of back flow prevention devices on both units.

Conclusion: It is Dominion's position that the evaluation and resultant corrective actions for the 2004 event were necessary and sufficient because the turbine building basement leakage was not an interconnected design issue and the leakage did not or could not compromise the established design prevention features. Therefore, Dominion considers that this event does not contain aspects relating to the cross-cutting area of problem identification and resolution.

II Actuator Oil Leakage on Turbine Interface Valve

1R14 Operator Performance During Non-Routine Evolutions and Events

a. Inspection Scope

The inspectors reviewed operator logs and plant computer data for the two events listed below to determine if plant and operator responses were in accordance with plant design, procedures, and training. The inspectors also evaluated performance and equipment problems to ensure that they were entered into the licensee's CAP.

- The inspectors evaluated the response of the Unit 1 and 2 control room operators on August 5 and 6, 2005, during an unplanned down power of Unit 1 for diaphragm replacement on 1-EH-TV-100, and,

- The inspectors evaluated the response of the Unit 2 control room operators on August 5 and 6, 2005, following an automatic reactor trip which occurred during the Unit 1 down power event above.

b. Findings

.2 Unit 1 Rapid Power Reduction Due to Loss of Turbine Auto Stop Oil Pressure

Introduction: An Apparent Violation having very low safety significance was identified for not performing Unit 2 corrective actions in a timely manner on Unit 1. This resulted in the Unit 1 rapid reduction in power from 100% to ≈8% (main turbine off-line) on August 5, 2005.

Description: On August 5, 2005, the licensee rapidly reduced power on Unit 1 due to severe oil leakage on the actuator for valve, 1-EH-TV-100 (Main Turbine Auto Stop Oil Interface Valve). Subsequent evaluations determined that the torque specifications of 12-13 ft-lbs. as specified in maintenance procedure 0-MCM-1412-01, "Main Turbine Interface Valve Diaphragm Replacement," did not provide adequate clamping force between the diaphragm and actuator cover flange faces which resulted in diaphragm movement and oil leakage from the actuator. The inspectors determined that an actuator oil leak from the same valve resulted in a manual trip due to low electro-hydraulic or auto stop oil pressure on April 19, 2003. The inspectors reviewed the root cause evaluation from the event and concluded that the licensee did not contact the vendor for specific torque values. The inspectors also reviewed a December 2004, event involving similar leakage on the Unit 2 equivalent valve. In this case, the resultant evaluation concluded that the interface valve diaphragm torque values should have been 20 ft-lbs. per vendor technical manual 59-264-00006, "Fisher Instruction Manual, Types 655 and 655R Actuators for Self-Operated Control." However, the inspectors determined that associated corrective actions for Unit 1 had not been implemented prior to the August 5, 2005 rapid down-power event.

Analysis: This finding has a credible impact on safety due to the challenge of plant control systems from the rapid reduction of power. The inspectors referenced IMC 0612 and determined that the finding was more than minor based on the impact to the Initiating Events cornerstone objective to limit the likelihood of those events that upset plant stability and the cornerstone attribute of equipment reliability. The inspectors referenced IMC 0609 for the SDP and determined that the finding is Green (very low safety significance) because it did not contribute to the likelihood of a primary or secondary system LOCA initiator or a loss of mitigation equipment functions, and did not increase the likelihood of a fire or internal/external flood. This issue is in the licensee's CAP as Plant Issue N-2005-2984. This finding contains aspects relating to the cross-cutting area of problem identification and resolution.

Enforcement: Since this finding is associated with nonsafety-related secondary equipment, no violation of regulatory requirements occurred. Therefore, this finding is identified as a Green finding FIN 05000338/2005004-04, Untimely Corrective Actions for Actuator Oil Leakage on Turbine Interface Valve Results in Rapid Down Power.

Dominion Response

On December 30, 2004, it was identified that oil drops were hanging from each bolt around the diaphragm of the Unit 2 Autostop Oil Interface Valve, 2-EH-TV-200. The oil was removed and the valve monitored. On December 31, 2004, oil was again identified in the threads of the diaphragm bolts, but no drops had formed. Subsequently, an engineering evaluation concluded that the interface valve diaphragm torque values should have been 20 ft-lbs. when the diaphragm was replaced. The maintenance procedure for diaphragm replacement was revised on July 14, 2005, to include the 20 ft-lbs. value.

As a result of the December observations, both units' Main Turbine Auto Stop Oil Interface Valves were being routinely monitored by Operations during normal rounds with periodic monitoring by System Engineering during their walkdowns. Since there was no observed active leakage at that time, checking the torque of both units' interface valves was not immediately performed due to the potential threat of tripping the units while online. The only means to completely address (i.e., valve disassembly) this issue immediately was to initiate a two-unit shutdown with the attendant risk associated in such an evolution. Based on the limited presence of oil leakage observed up to that point and the associated risk of immediate action, a decision was made to continue monitoring and await the first available and more appropriate time to check the torque of the diaphragm bolts.

Due to a minor leak on one bolt, on August 1, 2005, the Unit 2 Main Turbine Auto Stop Oil Interface Valve (2-EH-TV-200) was torqued to 12 ft-lbs. Based on the lack of leakage and past history indicating satisfactory performance of 1-EH-TV-

100, checking the torque on 1-EH-TV-100 was not immediately attempted. Work requests to check the torque on 1-EH-TV-100 were written with plans to implement during the week of August 8, 2005. Again, at the time there were no immediate operability concerns. On August 5, 2005, Dominion rapidly reduced power on Unit 1 due to severe oil leakage on the actuator for 1-EH-TV-100. The diaphragm was replaced and torqued to 20 ft-lbs. in accordance with the revised maintenance procedure.

Conclusion: It is Dominion's position that problem identification was appropriately documented and the resolution had been purposefully scheduled to minimize the risk of tripping the units. As a consequence, we conclude that this event should not be considered as a cross-cutting concern in the area of problem identification and resolution, as the identification and resolution process were purposefully and reasonably exercised.

III. Quench Spray Pump Safety Related Breaker

1R22 Surveillance Testing

a. Inspection Scope

For the nine surveillance tests listed below, the inspectors examined the test procedure, witnessed testing, and reviewed test records and data packages, to determine whether the scope of testing adequately demonstrated that the affected equipment was functional and operable, and that the surveillance requirements of the TS were met:

- 1-PT-63.1A, "Quench Spray System "A" Subsystem (1-QS-P-1A)," an inservice test,
- 2-PT-71.2Q, "Unit 2 Motor Driven Auxiliary Feedwater (2-FW-P-3A) Pump Test;" 1-PT-52.2, "Reactor Coolant System Leak Rate (Hand Calculation) VPAP-0502 – Procedure Process Control;"
- 2-PT-82J, "2J Diesel Generator Test Slow Start Test;"
- 2-PT-63.1B, "Quench Spray System – "B" Subsystem;"
- 2-PT-213.8B, "Valve Inservice Inspection ("B" Train of Safety Injection System);
- 2-PT-31.7, "Pressurizer Level Channel (2-RC-L-2459) Channel Operational Test;"
- 1-PT-75.2B, "Unit 1 Service Water Pump (1-SW-P-1B);" and,
- 2-PT-57.1B, "Emergency Core Cooling Subsystem – Low Head Safety Injection Pump (2-SI-P-1B)."

b. Findings

.1 Failure to Follow Procedures During SSPS Testing

Introduction: A Green, self-revealing NCV of TS 5.4.1.a was identified for failure to implement a surveillance procedure, which resulted in placing an incorrect bistable in a trip condition.

Description: On July 22, 2005, during performance of SSPS testing on Unit 2 in accordance with procedure 2-PT-31.7, "Pressurizer Level Channel I (2-RC-L-2459) Channel Operational Test," of which step 6.1.5 requires placement of trip switches BS1 and BS2 on card C1-442 in the trip position, instrument technicians incorrectly placed switches BS1 and BS2 on card C1-422 (same switch designation but a different card) in the test position, which initiated an unexpected alarm (LO LO Tave Interlock Loop 1 A-B-C) in the control room. This caused Unit 2, Loop 1 T cold inputs to the SSPS Relays K148 (Lo Lo Tave) (BS1) and K140 (Lo Tave)(BS2) to fail-safe and show a trip condition. A subsequent review by the inspectors of I/C drawings revealed that these relays were Channel I inputs for P-12 (Lo Lo Tave Steam Dump Interlock) and feedwater isolation permissives. The inspectors concluded that since loops two and three were not in a trip condition, the two out of three logic was not satisfied, and the plant was not affected.

Analysis: The inspectors reviewed IMC 0612 and determined that the finding was more than minor because it could reasonably be viewed as a precursor to a more significant event. If another channel in the logic had already been tripped, the plant would have been adversely affected by the performance deficiency. The inspectors consulted IMC 0609 for the SDP and determined that the finding is Green (very low safety significance) because it did not involve any LOCA indicators, did not contribute to both a reactor trip or mitigating system unavailability, nor increase the likelihood of a fire. This finding contains aspects relating to the cross-cutting area of human performance.

Enforcement: TS 5.4.1.a requires that written procedures shall be established, implemented, and maintained as documented in RG 1.33, Appendix A, of which Part 8 stipulates procedures for surveillance tests. Procedure, 2-PT-31.7.1, step 6.1.5 states, "Place the following comparator trip switches in TEST: On card C1-442, BS1 and BS2." Contrary to the above on July 22, 2005, step 6.1.5 was improperly implemented in that comparator switches BS1 and BS2, on Card C1-422 were placed in trip as opposed to the switches on the correct card, C1-442. This finding is of very low safety significance or Green, is in the licensee's CAP as Plant Issue N-2005-2755, and thus is characterized as an NCV, consistent with Section VI.A of the NRC's Enforcement Policy: NCV 05000339/2005004-04, Failure to Follow Procedure During Solid State Protection System Testing.

Dominion Response

The event described above did include a human performance error. However, this error was immediately identified and the channel returned to service. Furthermore, the testing was stopped until the issue could be understood and resolved.

The plant was not adversely affected because loops two and three were not in a trip condition and the human performance issue was immediately resolved. Without consideration of potential additional failures, this issue did not significantly impact the Initiating Events cornerstone and should not be considered as meeting the criteria for a cross-cutting issue. To escalate human performance deficiencies with the burden of additional single failures would render all procedural errors as substantive cross cutting issues.

Conclusion: Dominion does not agree that the identified human performance deficiency should be considered as relating to the cross-cutting area of human performance since the Initiating Events cornerstone was not significantly and therefore not substantively affected by the immediately corrected error.

.2 Failure to Follow Procedures Affecting Safety-Related Breakers

Introduction: A Green, self-revealing NCV of TS 5.4.1.a was identified for a failure to follow procedures resulting in a trip of the Unit 2 Quench Spray Pump, 2-QS-P-1B.

Description: On August 19, 2005, during performance of testing of 2-QS-P-1B per 2-PT-63.1B, "Quench Spray System – B Subsystem," the respective motor breaker, 2-EE-BKR-24J1-4, closed then immediately tripped open. The licensee subsequently determined that two of the three as-found phase values of the breaker overload device instantaneous pickup were low when compared to the North Anna Setpoint Document (NASD) procedure which contains the setpoints, trip times and test currents for all overload trip devices for 480-volt BBC/ITE K-line Breakers. Therefore, the motor starting current of approximately 3028 amps compared to the overload instantaneous setpoints of 2268 amps and 2912 amps for B and C phases respectively resulted in a premature trip of the breaker. The licensee previously performed maintenance on this breaker on February 19, 2005, when the overload devices were set and tested in accordance with electrical maintenance procedure, 0-EPM-302-02, "BBC/ITE 480-volt K-line Breaker and Associated Switchgear Cubicle Maintenance," which references NASD. Procedure 0-EPM-302-02, step 6.19.4.a.2 states, "If the trip setpoint is within tolerance (80-100 percent) that was recorded in step 6.19.1, then go to substep 6.19.4.b, and if not, then make adjustments using Attachment 5, Instantaneous and Short-Time Pickup Adjustment, and repeat steps 6.19.4.a.1 and 6.19.4.a.2." Contrary to the above, the technician performing the maintenance left the B and C phase instantaneous overload setpoints low outside of the allowable procedural tolerance at 3030 & 3002 amps respectively instead of within the allowable procedural tolerance of 3080 to 4620 amps. The

licensee determined that a contributing cause was setpoint drift on the associated overload device. However, the inspectors determined that given the worst case drift, B phase at 812 amps, and an initial setpoint of 3850 amps (middle of the established ban), the resulting drift would have resulted in a value above the motor starting current.

Analysis: The inspectors referenced IMC 0612 and determined that the finding was more than minor because it affected the Barrier Integrity cornerstone objective to provide reasonable assurance that the containment physical design barriers protect the public from radio nuclide releases caused by accidents or events and the cornerstone attribute of human performance. The inspector referenced IMC 0609 for the SDP and determined that the finding is Green (very low safety significance) because it did not impact design deficiencies, result in a loss of system safety functions, exceed related TS outage times, nor involve a seismic, flooding, or severe weather initiating event. This finding contains aspects relating to the cross-cutting area of human performance.

Enforcement: TS 5.4.1.a requires that written procedures shall be established, implemented, and maintained as documented in RG 1.33, Appendix A, of which Part 9 stipulates procedures for maintenance. Procedure 0-EPM-302-02, step 6.19.4.a.2 stated, "If the trip setpoint is within tolerance (80-100 percent) that was recorded in step 6.19.1, then go to substep 6.19.4.b, and if not, then make adjustments using Attachment 5, Instantaneous and Short-Time Pickup Adjustment, and repeat steps 6.19.4.a.1 and 6.19.4.a.2." Contrary to the above, on February 19, 2005, this step was not properly implemented or followed resulting in improper instantaneous overload setpoints on B and C phases and a subsequent trip of 2-QS-P-1B. This finding is of very low safety significance or Green, is in the licensee's CAP as Plant Issue N-2005-3225, and thus is characterized as an NCV, consistent with Section VI.A of the NRC's Enforcement Policy: NCV 05000339/2005004-05, Failure to Follow Procedures Affecting Safety-Related Breakers.

Dominion Response

The procedure implementation issue is correct as stated. However, contrary to the conclusions stated above, the root cause evaluation (RCE) determined that instrument drift was the direct cause of the pump trip. The instantaneous overload device on Breaker 2-EE-BKR-24J1-4 had drifted 27.3% from the previous as-left setpoint. This is outside the acceptance criteria of ±20% outlined in BBC Bulletin IB-8203 (Procedure for Field Testing/Calibration of ITE K-Line Overcurrent Trip Devices). It should be noted that the identified drift, by itself, was sufficient to cause the breaker failure.

The calibration was performed on February 19, 2005, and the pump was successfully started twice prior to the failure on August 19, 2005. A human performance error did occur when the trip setpoints were being installed on the breaker. However, this error was not the cause of the subsequent failure. Had

incorrect setpoints been the cause of this event the pump would not have passed the post maintenance test.

As clarification, "3002 amps" noted in the description section in the IR above is typed incorrectly, it should have read 3020 amps.

Conclusion: Dominion does not agree that the event contained aspects relating to the cross-cutting area of human performance since the root cause was determined to be instrument drift. Specifically, the human performance deficiency was not substantive and did not cause the pump trip nor impact a ROP cornerstone directly.

IV. TDAFW Outboard Bearing Leak

4OA2 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed the licensee's assessments and corrective actions for Plant Issue N-2005-2320, "during the performance of 1-PT-71.1Q (1-FW-P-2, Turbine Driven Auxiliary Feedwater (TDAFW) pump), noted the outboard bearing slinger ring leaking oil at approximately 3-4 drops per second." The Plant Issue was reviewed to ensure that the full extent of the issue was identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. The inspectors also evaluated the Plant Issue against requirements of the licensee's CAP as specified in VPAP-1601, "Corrective Action Program, "VPAP-1501, "Deviations," and 10 CFR 50 Appendix B. Additional documents reviewed are listed in the Attachment.

b. Findings and Observations

No findings of significance were identified. On June 12, 2005, the licensee initiated Plant Issue N-2005-2320 in response to an oil leak on the Unit 1 TDAFW pump outboard bearing identified during the quarterly surveillance test. The licensee completed a functional evaluation and declared a GL 91-18 condition (operable but degraded) for the component. During subsequent testing, the licensee better quantified the leak at 1.58 gallons per day as opposed to the original estimate of 8.5 gallons per day. The inspectors verified the licensee's functional evaluation which considered the following facts that the design basis accident mission time for TDAFW operation is 8 hours and that the pump oil reservoir is maintained at 12 – 18 gallons of which 8 gallons are below pump suction. This would result in leakage of .53 gallons during the 8-hour mission time resulting in the maintenance of pump operability. The inspectors reviewed the history of bearing oil leaks for the Unit 1 and 2 TDAFW pumps which included work order, 00505761-01, for an oil leak on the Unit 1 TDAFW pump outboard bearing which was completed on September 18, 2004. The licensee subsequently identified this corrective action as rework. The inspectors also

found for the Unit 2 TDAFW pump an Item Equivalency Evaluation Review (IEER) report, N95-5022-00, which installed new seals of a different design due to similar problems of oil leakage. The licensee could not explain why this same design had not been considered for the Unit 1 TDAFW pump. The inspectors reviewed the IEER process as implemented by VPAP-0708, "Item Equivalency Evaluation," and the corrective action process as implemented by VPAP-1601 and VPAP-1501. The inspectors determined that VPAP-0708 did not perform an extent of condition review nor reference, consider or require a plant issue. The inspectors also determined that neither VPAP-1601 or VPAP-1501 discussed the IEER process as a part of the CAP. The inspectors concluded that the failure to implement adequate corrective action for the Unit 1 TDAFW pump constituted a minor violation. This finding is not yet captured in the licensee's corrective action program.

Dominion Response

The minor violation as stated is incorrect. VPAP-0708, Item Equivalency Evaluation, establishes the requirements and methodology to ensure that alternate replacement parts are evaluated for their interfaces, interchangeability, form, fit, and function for parts installed in safety and non-safety related systems/components. This process (IEER report, N95-5022) was used in 1995 to justify the installation of seals of a different design on the Unit 2 TDAFW pump due to a problem with oil leakage. The new seal design supported by the IEER resolved the oil leakage issue on the Unit 2 TDAFW pumps. However, due to the continued and extended satisfactory performance of the Unit 1 seals, it was not considered necessary or desirable to take immediate actions to replace the existing seals with a design with no previous operational experience at North Anna. The Unit 1 TDAFW pump's oil seals continued to operate satisfactorily for the next nine years. Once minor oil leakage was identified, as documented in PI N-2005-2320, corrective actions were initiated. The Operational Decision Making Report, written in response to PI N-2005-2320, determined the oil leak will not affect the TDAFW pump's ability to perform its design function for its established mission time. Therefore, installation of new pump seals was scheduled for the Spring 2006 Unit 1 refueling outage.

Conclusion: Dominion does not agree that this issue constitutes a minor violation relating to the identification and resolution of problems. Replacement of the Unit 2 TDAFW pump seals used a process to ensure equivalency for the replacement seal. The original design seal was still acceptable to perform its design function, and it did just that. The initial Unit 2 seal leaks were corrected by a change in seal design and the Unit 1 seals were monitored. The Unit 1 TDAFW pump operated satisfactorily for 9 years before a minor leak was identified. Once leakage was identified on the Unit 1 TDAFW pump, corrective actions were scheduled commensurate with the safety significance.