UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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March 09, 2006

EA-06-02

Virginia Electric and Power Company
ATTN: Mr. Eugene S. Grecheck
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Innsbrook Technical Center - 2SW
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SUBJECT: RESPONSE TO DISPUTED MINOR VIOLATION AND FOUR CROSS-CUTTING ASPECTS CONTAINED IN NRC INTEGRATED INSPECTION REPORT NOS. 05000338/2005004 AND 0500339/2005004 - NORTH ANNA POWER STATION UNITS 1 & 2

Dear Mr. Grecheck:

I am writing in response to your letter dated December 9, 2005, in which you documented your disagreement with several elements of NRC Inspection Report Nos. 05000338/2005004 and 0500339/2005004 dated October 28, 2005. In your December 9, 2005, letter, you contested the minor violation and the existence or significance of four cross-cutting aspects described in the inspection reports. Your letter provided reasons to support your contentions.

The NRC has carefully reviewed the documentation provided to support your positions. Based upon our review, we have concluded, for the reasons outlined in the attached enclosure, that the finding, which was identified during an annual inspection sample for identification and resolution of problems, was appropriately classified as a minor violation. Three of the four contested cross-cutting aspects occurred as stated. One non-cited violation (NCV) was reclassified as a minor violation, therefore the NRC will modify the inspection reports appropriately to reflect this reclassification. As a minor violation, it also does not contribute to the assessment process used to determine if there is a substantive cross-cutting issue.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Should you have any additional questions, please contact Kerry Landis at (404) 562-4510.

Sincerely,

/RA by Stephen J. Cahill Acting for/

Charles Casto, Director
Division of Reactor Projects

Docket Nos.: 50-338/339
License Nos.: NPF 4, NPF 7

Enclosure: RESPONSE TO DOMINION'S DISAGREEMENT WITH INSPECTION REPORT NOS. 05000338/2005 AND 0500339/2005004

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RESPONSE TO DOMINION'S DISAGREEMENT WITH

INSPECTION REPORT 05000338, 339/2005004

I. Inspection Report Extract and Licensee Comment - 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 (URI).

Discussion. On July 9, 2005, back flush of control room chiller service water strainers 2-HV-S-1A and 1B as directed by engineering transmittal, ET –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 the 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.

<u>Analysis</u>. 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 the cross-cutting area of problem identification and resolution.

<u>Enforcement</u>. 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, requires the establishment of measures to assure conditions adverse to quality are promptly and 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.

NRC Evaluation of Dominion’s Response:

Analysis: To satisfy the requirements of NRC Generic Letter 88-20 the licensee performed a probabilistic risk assessment for internal flooding which included field walkdowns to identify possible flood sources and paths. The results were published in "Probabilistic Risk Assessment for the Individual Plant Examination Final Report North Anna Units 1 and 2 December 1992," and subsequently validated by additional field walkdowns in 2001. In response to the initial study the licensee performed modifications which added flood walls and back flow preventers in various floor drains. However, in both cases noted above, the field walkdowns failed to identify the flood path via floor drains between the chiller room and the adjacent fan room located in the emergency

switchgear area. In 2004, the licensee initiated prompt identification and correction of deficiencies relating to Plant Issue N-2004-4554. This presented an opportunity to identify and correct the absence of back-flow preventers in the Unit 1 and 2 ACFRs. After consultation with the Office of Enforcement, this violation is better characterized as a violation of 10 CFR 50, Appendix B, Criterion III, Design Control, in that the licensee failed to assure that the design change requiring back-flow preventers in the Unit 1 and 2 ACFRs were appropriately specified and implemented. Final documentation of this violation will be accomplished during the closeout of this URI.

The NRC reviewed Plant Issue N-2004-4554 and identified a comment in the evaluation response section 3), regarding failure of a flood wall between the air conditioning chiller room (ACCR) and turbine building area resulting in leakage to the ACCR from a postulated turbine building flood. The NRC also identified the following comment, "NOTE: There is a flood wall in the ESGR that would prevent any water in the chiller room from entering the ESGR." The NRC noted that the ESGR is the emergency switchgear room which is used by the licensee to denote a general area that also contains the solid state protection system (SSPS) and process instrumentation room and air conditioning fan room. The NRC also noted that the ACCR is between the turbine building and the ESGR and that a flood wall is located at each door for the ACCR. Therefore, the above information demonstrates that the licensee considered a flood situation starting in the turbine building and potentially involving the ESGR areas via the ACCR. However, the licensee's evaluation assumed that the flood wall between the ACCR and ESGR was adequate and, therefore, did not include more rigorous steps such as walkdowns and or consideration of operating experience (OE), which could have revealed the floor drain issue. The licensee's corrective action database contained significant OE. The NRC Integrated Inspection Report Nos. 05000338/2005004 and 05000339/2005004 mentioned one, Plant Issue N-1999-3405, regarding a Three Mile Island plant issue of check valves missing from floor drains and the impact on flood protection. The NRC also identified another OE example: Plant Issue N-1990-0020, "IN 83-44-S1: Potential damage to redundant safety equipment as a result of backflow through the equipment and floor drain system."

<u>NRC Conclusion:</u>

After consultation with the Office of Enforcement, this violation is better characterized as a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. Final documentation of this violation will be accomplished during the closeout of this URI. During the NRC review of Plant Issue N-2004-4554, the inspectors identified a comment in the evaluation response which addressed a flood scenario between the ACCR and ESGR which included the SSPS instrumentation room. This evaluation missed an opportunity to identify the absence of back-flow preventers in the adjacent ACFR floor drains. Consequently, this design control finding contains aspects of the cross-cutting area of problem identification and resolution.

II. Inspection Report Extract and Licensee Comment - 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 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.

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

Introduction: A Green, self-revealing finding was identified for not performing Unit 2 corrective actions in a timely manner on Unit 1. This resulted in the Unit 1 rapid reduction of 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 reactor trip due to low electro-hydraulic or auto stop oil pressure on April 19, 2003. The inspectors reviewed the root cause evaluation from that 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 had 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 plant 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-1 00. 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 should not be considered a

cross-cutting concern in the area of problem identification and resolution, as the identification and resolution process were purposefully and reasonably exercised.

NRC Evaluation of Dominion's Response

Analysis: Dominion stated that a subsequent engineering evaluation concluded that the diaphragm torque value should have been 20 ft-lbs when the valve diaphragm was previously replaced on 2-EH-TV-200, and that a procedure change to include the 20 ft-lb value was completed on July 14, 2005. The NRC determined that the licensee documented their awareness of the required torque value on March 22, 2005, in Plant Issue N-2004-5408 which also included statements about the vendor technical support staff acknowledging that the required torque setting is different from the licensee's current torque valve specified by procedure and, "He was more concerned about the low actuator diaphragm casing torque value, since this is directly responsible for retaining the diaphragm." The plant issue also stated that eminent failure of the diaphragm is not expected at the current torque valve, since it has been used successfully for the past 25+ years. However, the NRC determined that this is an incorrect statement based on the similar event that resulted in a manual reactor trip on April 19, 2003. The NRC identified that operating experience, OE 17170: Turbine Lube Oil Interface Valve Oil Leak, as listed in the licensee's corrective action program as simply "Plant Issue", was received on October 30, 2003, and reviewed on November 5, 2003, and is, therefore, within the 2 year window of the August 5, 2005 down-power event. The licensee's review of this OE stated, "Close: No definitive root cause information provided; RCE N-2003-1761 addresses the torque p(r)ocess under section 4.2; FYI for technical information." The NRC review of section 4.2 found that the only statement addressing torque information was, "Turbine Generator Coordinator (TGC) oversight of the diaphragm cover installation torque process will also be added." The NRC concluded that this failure to determine the correct torque requirements from the Plant Issue addressing OE 17170 is also inadequate corrective action.

Dominion stated that the only means to completely address this issue immediately was to initiate a two-unit shutdown with the attendant risk associated in such an evolution. Yet, the NRC noted that Dominion also performed maintenance with Unit 2 in service based on their statement that 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. The NRC reviewed the associated work order, 00605404-01, "Torque Diaphragm casing bolts," and noted that the actions taken were, "Set torque wrench to 12 ft.lbs. Tightened bolting outside leak working inwards to center leak. Did the same on the opposite side. All bolts except the one at the south side leak have less than 12 ft.lbs. The bolt at southside leak is torqued to 12 ft.lbs." The NRC also reviewed engineering logs and noted that the entry dated August 5, 2005, at 1043 hours, stated that an oil drop had accumulated on the bottom of the North bolt location for the Unit 1 valve, 1-EH-TV-100. This is different from previous entries which denote only slight seepage, no oil drips.

The potential for the valve diaphragm to rapidly degrade causing a plant transient was demonstrated by the fact that an oil drop had accumulated on Unit 1 valve, 1-EH-TV-100 on August 5, 2005, at 1043 hours and subsequently that day Dominion rapidly reduced power on Unit 1 due to severe oil leakage on the actuator for

1-EH-TV-100.

NRC Conclusion:

The NRC determined that Dominion had specific knowledge that:

1. The licensee was aware of the fact that the licensee's Turbine Interface Valve bolt torque requirement of 12 ft.lbs was less than the vendor specified torque requirement of 20 ft.lbs. Additionally the licensee knew that adequate torque was critical to retaining the diaphragm as documented in the March, 22, 2005, Plant Issue response following the December 2004 event involving similar leakage on the Unit 2 Main Turbine Auto Stop Oil Interface Valve, 2-EH-TV-200;
2 The 2-EH-TV-200 bolting was found with less than 12 ft.lbs torque values after valve maintenance was performed on August 1, 2005, with the unit remaining in service; and extent of condition on Unit 1 was not evaluated;
3. An increase in the oil leakage was noticed on 1-EH-TV-100 actuator on the morning of August 5, 2005, and later during that day increasing oil leakage resulted in a rapid down-power event.

Dominion failed to take adequate and timely corrective action for the actuator oil leakage on the Unit 2 Turbine Interface Valve following the December 2004 event to preclude the Unit 1 rapid down-power event on August 5, 2005.

III.1. Inspection Report Extract and Licensee Comment - Quench Spray Pump Safety Related Breaker - Finding relating to SSPS Testing:

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 the 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 initiators, 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 per 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.

NRC Evaluation of Dominion's Response:

Analysis: The Dominion response agrees that the event did include human error, however, the licensee makes three other points: (1) the human performance issue was immediately resolved, (2) 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, and (3) To escalate human performance deficiencies with the burden of additional single failures would render all procedural errors as substantive cross cutting issues.

Point 1: Whether the event was immediately corrected by returning the channel to service has no bearing on the fact that human performance was a contributing cause of the event or the identification of a human performance as a aspect of the event.

Point 2: The description and analysis In the inspection report referenced the other channels of SSPS logic to clearly state that the plant was not effected. The licensee appears to be taking issue with this violation being more than minor rather than meeting the criteria for a cross-cutting issue.

Point 3: The case is being made that since there was no additional single failure that any violation in this circumstance should not be characterized as more than minor because the condition did not involve actual consequences affecting safety and/or operability. After further review of IMC 0612, Appendix E.4. Example b, this violation closely matched this example and is being reclassified as a minor violation.

NRC Conclusion:

The SSPS testing event was a procedure violation involving a human performance error, however it is a minor violation based upon matching closely example b described in IMC 0612, Appendix E.4. Consequently, this minor violation and its cross-cutting aspect will not be part of the evaluation to determine if there is a substantive cross-cutting issue.

III.2. Inspection Report Extract and Licensee Comment - Quench Spray Pump Safety Related Breaker - Finding relating to the breaker overload device instantaneous pickup:

1R22 <u>Surveillance Testing</u>

a. <u>Inspection Scope</u>

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. <u>Findings</u>

.2 <u>Failure to Follow Procedures Affecting Safety-Related Breakers</u>

<u>Introduction</u>. 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.

<u>Description</u>. On August 19, 2005, during performance 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 and 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 & Associated Switchgear Cubicle Maintenance," which references the NASD. Procedure 0-EPM-302-02, step 6.19.4.a.2 states, "If the trip setpoint is within tolerance (80-120 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 inspectors 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 (80-120 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.

NRC Evaluation of Dominion’s Response:

Analysis: Subsequent to issuance of NRC Inspection Report 05000339/2005004 the root cause evaluation (RCE) determined that instrument drift was the direct cause of the pump trip. The NRC agrees that the A phase overcurrent instrument setpoint drift was sufficient to trip the breaker. However, during review of the RCE, the inspectors observed that even if the A phase setpoint had not drifted, the C phase as-left setpoint could reasonably be expected to trip the breaker during some starts. The starting current for the motor varies from the locked rotor current of 1750 amps to the maximum calculated inrush current of 3028 amps depending upon the AC phase angle when the breaker closes. Thus, the human error associated with leaving the C phase overcurrent setpoint at 3020 amps, which was outside the allowable band, could randomly cause a breaker trip. Furthermore, the NRC inspectors observed in the RCE that the allowable band of 3080 to 4620 amps was unacceptable. The lower value of 3080 is only 52 amps above the maximum calculated inrush current of 3028 amps. This does not provide sufficient margin to allow for possible instrument setpoint drift during the five year calibration interval to prevent tripping of the breaker during a demand start. The RCE also identified a contributing human performance error. The licensee identified that the overcurrent instrument setpoint was approximately 20% lower than the requirements in the North Anna Setpoints Document. Thus, the NRC considers that the event revealed two human performance issues which directed impacted the reliability of the Unit 2 “B” Quench Spray Pump.

This finding has a cross-cutting “aspect” of human performance and by itself does not constitute a “substantive” cross cutting issue relative to human performance and procedure errors.[1]

NRC Conclusion:

Although the NRC acknowledges that the A phase setpoint drift tripped the breaker, there is no evidence that only the A phase tripped the breaker. As noted above, the

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[1]From MC 0305, “a substantive cross-cutting issue should be corroborated by the existence of a significant number (more than three (3)) of findings. The findings should share a common performance characteristic more specific than the three cross-cutting areas and should be from more than one cornerstone. However, it is recognized that given the significant inspection effort applied to the mitigating systems cornerstone, that a substantive cross-cutting issue may be observed through inspection findings associated with only this one cornerstone.”

human errors associated with the as-left C phase setpoint and allowable band also provided a mechanism for the breaker to trip at some random interval and thus impacted the pump's reliability. The NRC considers the identification of a human performance cross-cutting "aspect" as appropriate and will be part of the evaluation to determine if there exists a "substantive" cross-cutting issue.

IV. Inspection Report With Contested Comment - 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 Auxilliary 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 the 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 21, 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 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 a 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, N95-5022-000, 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 part of the CAP. The inspectors concluded 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 –2005-2320, corrective actions were initiated. The Operational Decision Making Report, written in response to PI –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.

NRC Evaluation of Dominion's Response:

Analysis: The inspection report states that: "the failure to implement adequate corrective action for the Unit 1 TDAFW pump constituted a minor violation." The minor violation involves failure to take adequate corrective action for the September 18, 2004, oil leak on the Unit 1 TDAFW pump outboard bearing. As noted in the inspection report, work order 00505761-01 was initiated to repair the oil leak. The work order documented as found and required clearances associated with the oil deflector. The required oil deflector running clearance on the outboard bearing is .050 to .060 inches. The as found clearance with the rotating element thrusted inboard was .052 inches. However, when the rotating element was thrusted outboard, the as found clearance was documented as .028 inches. The inspectors noted that there was no engineering review signature on the work order. Additionally, the work order stated that the oil film may have come from oil spillage during the pre-lube of the outboard bearing prior to a surveillance test. This assumption was not verified as being accurate by an additional run of the Unit 1 TDAFW pump. The inspectors could find no other corrective action

document which evaluated the cause of the leak or specified corrective actions to be implemented such as continued monitoring during future pump tests. Subsequently, the oil leakage on the Unit 1 TDAFW pump outboard bearing resulted in initiation of a Plant Issue on June 21, 2005. The licensee performed an operability evaluation on July 8, 2005, and determined the Unit 1 TDAFW pump was operable, but degraded. The root cause evaluation has been delayed until the refueling outage planned for March 12, 2006, at which time the licensee has planned to implement a modification to replace the oil deflector seal with a labyrinth seal similar to that previously installed on the Unit 2 TDAFW pump. A seal oil leak is a condition adverse to quality, and thus actions are required to identify and correct the problem as specified in 10 CFR 50 Appendix B, Criterion XVI. This issue was inspected as an annual inspection sample for identification and resolution of problems and documented as a sample required by the inspection program. Using NRC guidance, this issue was also evaluated and identified as being a minor violation.

The discussion concerning the IEER process involved the inspectors' observations concerning historical information about previous corrective actions for earlier leaks. While the inspectors were reviewing available documentation to see if proper corrective action was documented for the Unit 2 TDAFW, the IEER documentation was found and reviewed. It was not considered as part of the minor violation.

NRC Conclusion:

The NRC considers failure to take adequate corrective action for the September 18, 2004, Unit 1 TDAFW pump outboard bearing seal oil leak as a violation, in that the inspectors could find no corrective action documentation which adequately evaluated the cause of the leak and specified corrective actions to be implemented to correct this condition adverse to quality. Subsequently, the Unit 1 TDAFW pump outboard bearing oil leak resulted in degraded operation of the Unit 1 TDAFW pump as documented in a Plant Issue on June 21, 2005. The IEER process was reviewed but not considered part of the minor violation.