VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

March 14, 2018

10CFR50.90

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Serial No.: 18-057
NRA/GDM: R0'
Docket Nos.: 50-280
50-281
License Nos.: DPR-32
DPR-37

VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION UNITS 1 AND 2
PROPOSED LICENSE AMENDMENT REQUEST
OPEN PHASE PROTECTION PER NRC BULLETIN 2012-01
CLARIFICATION OF REQUEST FOR ADDITIONAL INFORMATION RESPONSE AND ASSOCIATED LICENSE AMENDMENT REQUEST REVISION

By letter dated May 23, 2017 (Serial No. 17-188), Virginia Electric and Power Company (Dominion Energy Virginia) submitted a license amendment request (LAR) to add operability requirements, required actions, instrument settings, and surveillance requirements to the Technical Specifications (TS) for the 4160V emergency bus negative sequence voltage (open phase) protection function. By letter dated January 16, 2018 (Serial No. 17-188A), Dominion Energy Virginia responded to an NRC request for additional information (RAI). A conference call was held with the NRC on January 31, 2018 to discuss the RAI response and to provide additional clarification. At the conclusion of the call, Dominion Energy Virginia agreed to provide a written summary of the clarification discussion. This information is provided in Attachment 1.

Dominion Energy Virginia has also determined the proposed LAR requires revision to address the condition where the open phase condition (OPC) negative sequence voltage protection function cannot be performed (e.g., due to its Potential Transformer (PT) Blocking Device being tripped). The previously proposed 90-day allowed outage time (AOT) has been revised to a 7-day terminal action to align with the existing TS requirements for undervoltage and degraded voltage protection. A discussion of the revised proposed change is provided in the response to the RAI No. 6 clarification request included in Attachment 1, and the affected marked-up and typed TS pages indicating the revised proposed change are provided in Attachments 2 and 3, respectively. The revised proposed change is indicated by double revision bars in the right hand margin.

The information provided in this letter does not affect the conclusions of the significant hazards consideration or the environmental assessment included in the May 23, 2017 LAR.

A001
NRR

Should you have any questions or require additional information, please contact Mr. Gary D. Miller at (804) 273-2771.

Respectfully,

Gerald T. Bischof
Vice President - Nuclear Operations - Fleet Performance

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO)

The foregoing document was acknowledged before me, in and for the County and Commonwealth aforesaid, today by Mr. Gerald T. Bischof, who is Vice President – Nuclear Operations - Fleet Performance, of Virginia Electric and Power Company. He has affirmed before me that he is duly authorized to execute and file the foregoing document in behalf of that company, and that the statements in the document are true to the best of his knowledge and belief.

Acknowledged before me this 14th day of March, 2018.

My Commission Expires: January 31, 2020

WANDA D. CRAFT
Notary Public
Commonwealth of Virginia
Reg. # 7520495
My Commission Expires January 31, 2020

Wanda D. Craft
Notary Public

Commitments contained in this letter: None

Attachments:

1. Clarification of Response to NRC Request for Additional Information Regarding the Proposed Open Phase Protection License Amendment Request

1. Revised Marked-Up Proposed Technical Specifications Page

2. Revised Proposed Technical Specifications Page

cc: U.S. Nuclear Regulatory Commission - Region II
Marquis One Tower
245 Peachtree Center Avenue, NE Suite 1200
Atlanta, GA 30303-1257

State Health Commissioner
Virginia Department of Health
James Madison Building – 7th floor
109 Governor Street
Suite 730
Richmond, VA 23219

Ms. K. R. Cotton Gross
NRC Project Manager – Surry
U.S. Nuclear Regulatory Commission
One White Flint North
Mail Stop 08 G-9A
11555 Rockville Pike
Rockville, MD 20852-2738

Mr. J. R. Hall
NRC Senior Project Manager – North Anna
U.S. Nuclear Regulatory Commission
One White Flint North
Mail Stop 08 B-1A
11555 Rockville Pike
Rockville, MD 20852-2738

NRC Senior Resident Inspector
Surry Power Station

Attachment 1

CLARIFICATION OF RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION REGARDING THE PROPOSED OPEN PHASE PROTECTION LICENSE AMENDMENT REQUEST

**Virginia Electric and Power Company
(Dominion Energy Virginia)
Surry Station Units 1 and 2**

Clarification of Response to NRC Request for Additional Information
Surry Power Station Units 1 And 2

By letter dated May 23, 2017 (Serial No. 17-188), Virginia Electric and Power Company (Dominion Energy Virginia) submitted a license amendment request (LAR) to add operability requirements, required actions, instrument settings, and surveillance requirements to the Technical Specifications (TS) for the 4160V emergency bus negative sequence voltage (open phase) protection function. By letter dated January 16, 2018 (Serial No. 17-188A), Dominion Energy Virginia responded to an NRC request for additional information (RAI). A conference call was held with the NRC on January 31, 2018 to discuss the RAI response and to provide additional clarification. At the conclusion of the call, Dominion Energy Virginia agreed to provide a written summary of the clarification discussion. This information is provided below.

RAI No. 1 Clarification Request:

The NRC requested clarification regarding how protection of the emergency buses would be maintained in the event the non-Class IE Alstom GE OPC detection relay failed.

Dominion Energy Virginia Response:

As shown in Figure 1 of Attachment 1 of Dominion Energy Virginia's license amendment request dated May 23, 2017 (Serial No. 17-188), the substation near Surry Power Station (SPS) consists of connections to both the 230kV and 500kV transmission systems. Off-site power is provided to the station through Switchyard Transformers No. 1 (connected to the 500kV bus), No. 2 (connected to 230kV bus #4), and No. 4 (connected to the 230kV bus #3). The 230kV and 500kV systems are independent and provide alternate sources of offsite power. Each of these three Switchyard Transformers is capable of independently providing power to an emergency bus on each Unit.

During normal operation, Reserve Station Service Transformer (RSST) C is connected to Switchyard Transformer No. 2 and supplies power to the Unit 1 'H' and Unit 2 'J' 4160V Emergency Buses. RSSTs A and B are connected to Switchyard Transformer No. 1. RSST A provides power to the Unit 1 'J' Emergency Bus and RSST 'B' provides power to the Unit 2 'H' Emergency Bus. Switchyard Transformer No. 4 can be connected to either RSST A and B or RSST C. Each of the two emergency buses per Unit are supplied through transfer buses by the RSSTs.

Failure modes for the non-Class IE Alstom Open Phase Detection (OPD) System implemented on Switchyard Transformer No. 1 were provided in Dominion Energy Virginia's January 16, 2018 response to the NRC Request for Additional Information. In the unlikely event that an open phase condition (OPC) occurs concurrent with an Alstom

OPD System failure resulting in loss of open phase detection, one emergency bus per unit remains unaffected due to the switchyard and transformer alignment described above. This ensures important to safety systems and components remain capable of performing their design function and are available for safe shutdown of the unit.

Furthermore, operators are notified of a Switchyard Transformer No. 1 OPD System failure by an annunciator in the Main Control Room and can realign the offsite power supply to RSSTs A and B from Switchyard Transformer No. 1 to Switchyard Transformer No. 4.

In summary, emergency power remains available to plant safety systems should a failure of the non-Class IE Alstom OPD System occur.

RAI No. 3 Clarification Request:

The NRC requested a summary of the worst case analyses, key assumptions used, and the results obtained for the loading conditions and operating configurations including plant trip(s) followed by bus transfers for OPC events that were evaluated in the supporting OPC calculations EE-0883, Revision 0, "Open Phase Condition Detection Analysis," and Calculation EE-0886, Revision 0, "Open Phase Condition Protection Analysis."

Dominion Energy Virginia Response:

The models and analyses that determined OPC vulnerabilities of the SPS on-site protection schemes for the safety buses, non-safety buses, and off-site power sources considered various power source alignments and operating conditions. Each alignment or condition represents a unique case. A summary of the open phase events, locations, generating conditions, and loading conditions considered in the cases was provided in Section 3.1 of Attachment 1 in the original License Amendment Request dated May 23, 2017. A summary of the key assumptions used in the analysis and results is provided below. Calculations EE-0883 and EE-0886 contain detailed descriptions and information, and relevant calculation sections are referenced when appropriate.

1) Key Assumptions

   Below are several key assumptions related to the OPC analysis performed for SPS. Refer to Section 8.0 of Calculations EE-0883 and EE-0886 for discussion of all the assumptions used in the analysis.

   - The maximum voltage source models (used to represent the maximum grid source voltage magnitude and maximum short circuit strength at the 230 kV and 500 kV switchyards) are assumed to be infinite sources.

Assuming an infinite source for maximum voltage source models will bound the performance of any impedance the system may have. Additionally, this will ensure this analysis remains bounding for future increases in transmission system strength. Therefore, this assumption is acceptable.

- It is assumed all transformer impedances are nominal regardless of the tap position. For fixed tap transformers where impedances were unavailable for tap points outside of nominal, the nominal impedance is converted to the new tap voltage. For transformers with a load tap changer (LTC), the transformer is modeled at the nominal tap and an additional ideal transformer is placed on the secondary of the transformer to model the selected tap output voltage. Variations of the ohmic impedance of a transformer are minor and therefore this assumption is acceptable.

- For accident scenarios, the open phase event is assumed to occur coincident with the safety injection (SI) / consequence limiting safeguards (CLS) signal. Based on Section 8.5 of the SPS Updated Final Safety Analysis Report (UFSAR), it is not necessary to evaluate the potential impacts of the performance of other systems resulting from a loss of offsite power (LOOP) subsequent to a loss of coolant accident (LOCA) because that scenario is not part of the Surry licensing basis.

- Rotors designed for motor-operated valve (MOV) applications do not rely on the deep bar design. The rotors are of high resistance (small area) conductors similar to the NEMA Design D (exhibiting both high starting torque and high slip). For these types of rotors, there is no significant skin effect; the rotor resistance at start, when s=1 (and at 2-s, the negative sequence frequency), is almost the same as that during the "running" condition. Therefore, the negative sequence heating criteria used to evaluate continuous duty induction motors is not applied to MOV actuator motors. Instead, MOV motors must be protected against prolonged locked rotor conditions that may occur during an OPC. A letter from Baldor-Reliance to Flowserve-Limitorque states, “Most curves published for Limitorque ratings show heating after a 10 second locked rotor condition”. Based on this statement, most MOVs can withstand a locked rotor condition for up to 10 seconds before starting to overheat. For the purposes of this analysis, it is conservatively assumed that MOV motors can withstand a locked rotor condition for up to 5 seconds and have adequate remaining capability to restart on the diesel generator.

- For RSST A, B and C, the zero sequence impedance is assumed 80% of the positive sequence impedance.

The RSSTs are Delta-Wye resistive grounded transformers. The zero sequence impedance seen looking through Delta-Wye resistive grounded transformers will be infinite due to the primary delta winding, and the ground fault current of the wye-grounded (X winding) will be dominated by the grounding resistor. This assumption will not have an impact on the calculation conclusions and does not require verification.

- For Switchyard Transformers 2 and 4, the zero sequence impedance is assumed to be 80% of the positive sequence impedance.

  Switchyard Transformers 2 and 4 are Delta-Wye solidly grounded transformers. Due to their configuration, the zero sequence short circuit impedance for these transformers will be approximately equal to the positive sequence impedance viewed from the Wye connection side. The zero sequence impedance can be higher or lower than the positive sequence depending on the transformer core design; however, here it is assumed to be 80% of the positive sequence impedance.

- It is assumed that the maximum impedance of a grounded open phase is 1000 ohms.

  References included in the analysis calculations provide a survey of the methods for calculating the resistance of high-impedance arcing faults on high voltage transmission systems. The most conservative method per the reference for calculating arc resistance is based on the empirical model proposed by A. Warrington, where the arcing-fault resistance is calculated based on the following equation:

$$R_{arc} = \frac{28707.35 * L}{I^{1.4}}$$

where R_{arc} is the arc resistance in ohms, L is the arc length in meters, and I is the root mean square value of the fault current in amperes. Using an arc-length of 38 ft (or 38ft * 0.3048 ft/m = 11.6m), based on typical phase spacing at 500 kV, the above equation is solved by iteration using the EMTP model of transformer TX-1, which results in an arc impedance of 148.4 ohms.

The total fault impedance using this method is composed of the arc resistance and the effective grounding resistance (tower footing resistance). The maximum effective grounding resistance (tower footing resistance) for the Surry switchyard is assumed to be 25 ohms based on engineering judgment. A typical value for tower footing resistance is 10 ohms or less for good line lightning performance. This results in a total fault impedance of 148.4 ohms + 25 ohms = 173.4 ohms. Therefore, the assumed open phase to ground impedance of 1000 ohms is conservative and this assumption does not require verification.

2) Resulting Voltage Unbalance during Open Phase Conditions

Table 13 below (Reference Calculation EE-0886, Section 12.1.1) shows a summary of the maximum and minimum steady-state negative sequence voltages seen at Buses 1H, 1J, 2H, and 2J for OPCs on the high voltage side of each transformer considered in the analysis. The table shows the following:

- For OPCs on Transformer No. 1 (wye-primary) the minimum negative sequence voltage is insufficient to actuate the negative sequence voltage relay. The minimum negative sequence voltage is 0.17V or (0.17V/120V = 0.14%) and the minimum setting on the Basler 47N relay is 2% on a 120V base. These cases should be detected by the proposed Alstom OPD system on Transformer No. 1.

- For OPCs on Transformers No. 2, No. 4, RSST A, RSST B, and RSST C (delta-primary) the minimum negative sequence voltage is above the minimum possible setting for the Basler 47N relay. The minimum observed negative sequence voltage was on Switchgear 2H for an open phase condition on Transformer No. 4. This equates to 13.39V/120V=11.2%. This is greater than the negative sequence voltage nominal 6% setpoint plus Channel Statistical Allowance (CSA) (9.05V for Buses 1H and 2H and 10.12V for Buses 1J and 2J).

- For OPCs on Generator Step-Up (GSU) transformers GSU 1 and GSU 2, the minimum negative sequence voltage is insufficient to actuate the negative sequence voltage relay. The minimum negative sequence voltage is 0.12V or (0.12V/120V = 0.1%) and the minimum setting on the Basler 47N relay is 2% on a 120V base. For the GSU 1 and GSU 2 cases that do not actuate the negative sequence voltage relays, analyses show that the OPCs either do not affect operating motors or the OPCs are cleared by existing generator protection schemes. (Refer to Calculation EE-0886, Section 12.1.2.2.)

Table 13 – Summary of Negative Sequence Voltages for Open Phase Conditions on each Transformer

Open Phase Location	Negative Sequence Voltage (L-L rms, at 4200:120 PT secondaries) t = 8 s							
	SWGR 1H		SWGR 1J		SWGR 2H		SWGR 2J	
	Min V2	Max V2	Min V2	Max V2	Min V2	Max V2	Min V2	Max V2
TX-1	*	*	0.17	66.57	0.17	68.46	*	*
TX-2	14.82	58.80	*	*	*	*	14.84	58.89
TX-4	14.52	58.82	15.05	59.64	13.39	61.27	14.53	58.91
RSSTA	*	*	18.62	59.64	*	*	*	*
RSSTB	*	*	*	*	16.45	61.50	*	*
RSSTC	16.86	58.82	*	*	*	*	16.88	58.92
GSU1 (Gen On)	1.28	10.45	0.13	10.61	0.17	10.96	1.28	10.46
GSU2 (Gen On)	0.12	2.11	0.16	6.69	0.20	6.91	0.12	2.11
GSU1 (Backfeed)	0.74	31.70	0.74	31.83	0.74	31.62	0.74	31.70
GSU2 (Backfeed)	0.85	35.68	0.85	35.57	0.85	35.63	0.85	35.68

3) Continuous Duty Induction Motor Protection

For voltage unbalance greater than 5%, the analysis results show that for all cases, the negative sequence voltage protection relays trip and isolate the motor loads before the integrated negative sequence current squared times time (I_2^2t) is equal to 20 pu. Note the results were developed based on the nominal 6% setting accounting for the CSA. These results show that thermal protection is afforded to the motors even if the response of the negative sequence voltage relays is shifted due to the maximum calculated CSA.

4) Transformer TX-1 Open Phase Cases

For single ungrounded open phases on the high side of transformer TX-1, there is insufficient negative sequence voltage to actuate the negative sequence voltage protection relays. However, the negative sequence voltage is greater than 1% on the motor nameplate voltage base. Analysis shows that the ungrounded open phase cases on the high-voltage side of TX-1 with loading up to 75% of the maximum station loading would not be detected by the BE1-47N with the minimum 2% pickup setting.

5) Generator Step-up Transformer GSU 1 and GSU 2 Open Phase Cases

With the generator online, an OPC on the high voltage side of the GSU results in voltage unbalance at the switchyard bus, which can be seen at the 4kV switchgear fed from the RSSTs. The generators have negative sequence current protection which is expected to operate for OPCs to trip the generator and clear the unbalance.

For single OPCs with the generator online, the highest negative sequence voltage seen at the 4kV switchgear is 3.49 V (or 3.49 V/120 V = 2.91% on the Basler relay base voltage), which is a single open phase on the high voltage side of GSU 1. In this case, the negative sequence voltage is less than the proposed 6% pickup setting for the Basler 47N relay, so the Basler relays are not expected to operate. The lowest observed generator negative sequence current for a single OPC at the high voltage side of the GSU is 8023A. Based on a 40000/5 CT ratio and a tap setting of 3.5 A, this equates to a per-unit negative sequence current of 8023 A / (40000/5) / 3.5 A = 0.29 pu. The generator negative sequence overcurrent relay is expected to trip in approximately 120 seconds for this case to clear the OPC. This is the longest expected tripping time for OPCs on the GSU with the generator online at power. Motor damage is not expected to occur in less than 120 seconds.

For double OPCs on the high voltage side of the GSU with the generator online, the affected generator was observed to fall out of step with the power system. This results in large voltage and current oscillations at the generator terminal. The existing generator impedance relays provide protection for an out-of-step condition. The generator impedance relay scheme is designed to detect the out of step condition and trip the unit within the first half-slip cycle in order to protect the generator from the stresses that occur during an out-of-step condition. Based on the power swings observed in the EMTP simulations, the generator trip is expected to occur within one second after the OPC occurs, which would mitigate the unbalance at the safety buses before the safety-related functions are impacted.

For single OPCs with the generator offline and the safety-related buses in back-feed configuration, the highest negative sequence voltage seen at the 4kV switchgear is 1.19 V, which is a single open phase on the high voltage side of GSU 2 with the minimum grid voltage source (Source #2) and maximum loading on the Station Service Transformers (SSTs). A negative sequence voltage unbalance of 1.19V on the 4200:120 PT secondary corresponds to a 1.0% negative sequence voltage on the 4000V motor base (1.19V * 4200/120) / 4000V = 1.0%. Based on the NEMA MG-1, induction motors can operate continuously without de-rate for a voltage unbalance of 1.0% or less. Note these cases consider the SSTs loaded up to the forced oil air rating, which is conservative. For cases with lighter loading, the voltage unbalance will be less than 1%.

For double OPCs with the generator offline and the safety-related buses in back-feed configuration, the lowest negative sequence voltage seen at the 4kV switchgear is 31.51 V (or 31.51 V/120 V = 26.3% on the Basler relay voltage base), which is a double open phase on the high voltage side of GSU 2. For these cases, the results show the Basler negative sequence voltage protection relays will detect the OPC and initiate a transfer of the safety-related buses to ensure the safety functions are preserved.

6) Diesel Generator Testing Cases

For a diesel test concurrent with a single ungrounded OPC, it was observed that the diesel test could mask the OPC by balancing the voltage at the 4kV buses. Thus, the negative sequence voltage relays will not be functional during a parallel emergency diesel generator test.

For one specific case, a negative sequence voltage of 4.86V (or 4.86V/120V = 4.05%) was observed. For this case, the negative sequence voltage relay with a 6% pickup setting may not detect the unbalanced condition. Note that the OPC would only affect one train per unit since the offsite supplies are separated. If an accident were to occur during diesel testing, the alternate train would be available to mitigate the accident. For one other specific case, a negative sequence voltage of 2.3V (or 2.3V/120V = 1.91%) was observed. This case may not be detected by the negative sequence voltage relay with a minimum 2% pickup setting. A negative sequence voltage unbalance of 2.3V on the 4200:120 PT secondary corresponds to a 2.0% negative sequence voltage on the 4000V motor base (2.3V *4200/120) / 4000V = 2.0%. Based on the NEMA MG-1 de-rating curve, a 2.0% voltage unbalance corresponds to a de-rating factor of 0.95 for continuous operation. With a 1.15 service factor, a motor can operate continuously if loaded to approximately full nameplate horsepower or less (0.95 * 1.15 = 1.09). The safety-related motors that operate during non-accident conditions have a brake horsepower of less than or equal to nameplate horsepower and will therefore be capable of operating continuously during this postulated condition. When the diesel is taken offline after testing, the voltage unbalance at the 4kV bus would increase above the pickup setting of the negative sequence voltage protection relay, and the relay would initiate a transfer of the bus.

7) Coordination with Existing Overcurrent Protective Devices

The results show that for all cases, with the settings described above, the negative sequence voltage protection relay and/or the existing undervoltage protection will trip before the existing safety-related overcurrent protective devices for an OPC and concurrent design basis accident. Therefore, coordination between the existing overcurrent protective devices and the negative sequence protection relays is achieved. Note that there are several apparent mis-coordinations between the negative sequence voltage relay and the overcurrent protective devices (i.e., the overcurrent protection will trip before the negative sequence voltage relay). For all of these cases, the only overcurrent protection device to trip in the first 7 seconds following the open phase event is the non-safety related RSST main secondary breaker relay. This trip only occurs during maximum RSST loading conditions where the station service buses are cross-tied to the RSSTs. If the RSST main secondary breaker tripped during the event, the downstream safety-related buses would still transfer to the alternate diesel generator source and there would be no loss of safety function. In addition, for most cases, the existing undervoltage protection schemes will operate in approximately 2 seconds; therefore, the overcurrent protection will not trip and the safety buses will be transferred to the diesel generator.

8) MOV Motor Protection

The results show that for all open phase cases in which the negative sequence protection relay trips, the combined tripping time of the negative sequence voltage relay and existing undervoltage protection is less than 5 seconds after the open phase event occurs. Therefore, the MOV motors will be protected and have sufficient remaining thermal capability to restart on the emergency diesel generators.

9) Open Phase Event Timing

For this analysis, the open phase protection relay tripping time delay should be less than or equal to 7 seconds for an open phase condition coincident with a SI/CLS signal based on the time delays considered in the accident analysis. The results show that for all open phase cases in which the negative sequence protection relay trips, the combined tripping time of the negative sequence voltage relay and existing undervoltage protection is less than 5 seconds after the open phase event occurs. That is, for all cases where the tripping time of the negative sequence voltage relay is 5 seconds or longer, the bus voltages on at least two of the three phases are less than the 2975V Technical Specifications (TS) limit for the loss of voltage relay. Thus for these cases, the loss of voltage relay will dropout and trip after a two second time delay. This is within the time considered in the accident analysis for a loss of offsite power coincident with an accident.

Note the CSA for the negative sequence voltage relay may delay the relay response time. Results show the nominal response curve for a 6% pickup and 10.0 time delay setting and shifted response curves to account for both positive and negative CSA. For conservatism, the CSA for Buses 1J and 2J are used in the plot as the CSA for these buses bound the CSA for Buses 1H and 2H. The plot shows that a 5 second trip time corresponds to a negative sequence voltage of approximately 17.5V on the nominal curve. For the same level of negative sequence voltage, the relay would trip in approximately 7 seconds considering the 6% pickup plus CSA. This is within the time considered in the accident analysis for a loss of offsite power coincident with an accident.

For OPCs on Transformer TX-1 that are not detected by the negative sequence voltage protection relay, the proposed Alstom OPD relay should detect the OPC and initiate a trip of the offsite source. A tripping time delay of less than or equal to 5 seconds will be employed for the Alstom OPD relay to be within the time considered in the accident analysis for a loss of offsite power coincident with an accident.

RAI No.5 Clarification Request:

The NRC requested a summary of the analytical limits for negative sequence voltage and time delays chosen for the Technical Specifications (TS) changes for OPC detection and protection that are provided in supporting OPC calculation EE-0886.

Dominion Energy Virginia Response:

1) Negative Sequence Relay Analytical Limits and Time Delay

The relays have a negative sequence voltage pickup setting of 6% on a 120V nominal voltage base and a time dial setting of 10.0. The relay is modeled in EMTP-RV based on the nominal trip curve. Calculation EE-0885 calculates the total CSA for the Basler BE1-47N relays. From Calculation EE-0885, the negative sequence voltage relays on Buses 1H and 2H may pick-up between 5.35V to 9.05V, and the negative sequence voltage relays on Buses 1J and 2J may pick-up between 4.28V to 10.12V. The analyses use the calculated CSA to ensure negative sequence voltage relays detect all consequential OPCs and transfer the safety related loads to the alternate source prior to a loss of safety function and within the timeframe assumed in the accident analysis considering the nominal 6% pickup setpoint plus CSA. (Refer to Calculation EE-0886, Section 9.7.)

2) Open Phase Event Timing

Based on Section 8.5 of the UFSAR, for an open phase event coincident with an SI or CLS signal, the emergency buses should be re-energized by the diesel generator within 10 seconds (the time delay assumed in the accident analysis), including a 2.2 second residual voltage time delay. To be within the time frame considered in the accident analysis, the open phase protection relay tripping time delay should be less than or equal to 7 seconds for an open phase event coincident with an SI or CLS signal. This is consistent with the time delay used for degraded voltage protection during accident conditions. (Refer to Calculation EE-0886, Section 11.4.)

The analysis results show that for all consequential open phase cases in which the negative sequence protection relay trips, the combined tripping time of the negative sequence voltage relay and existing undervoltage protection is less than 5 seconds after the open phase event occurs. That is, for all cases where the tripping time of the negative sequence voltage relay is 5 seconds or longer, the bus voltages on at least two of the three phases are less than the 2975V TS limit for the loss of voltage relay. Thus, for these cases, the loss of voltage relay will dropout and trip after a two second time delay. This is within the time considered in the accident analysis for a loss of offsite power coincident with an accident. (Refer to Calculation EE-0886, Section 12.1.5 and Attachment A.)

<u>RAI No.6 Clarification Request:</u>

The NRC requested additional justification for the 90-day completion time (i.e., allowed outage time) requested for the required action if the negative sequence voltage (open phase) protection function cannot be performed (e.g., the Potential Transformer Blocking Device is tripped). The staff notes the proposed operator action 27 for limiting condition of operation for an inoperable open phase protection function is 90 days. The 90 days to maintain operability of the OPC automatic protective function is inconsistent with other relays specified in Surry TS Table 3.7-2 for loss of power instrumentation. Since the inoperable relay cannot take any automatic protective function for an OPC, it remains connected to the Class 1 E ESF 4160V buses downstream and could render the onsite emergency power system incapable of performing its designated safety function. Therefore, please provide either justification for the completion time of 90 days or provide appropriate markup of changes in the TS for the required action for inoperable OPC relay consistent with 10 CFR 50.36(c)(2).

Dominion Response:

As stated in the January 16, 2018 letter (Serial No. 17-188A) in the response to RAI No. 6 in Attachment 1, the proposed Operator Actions 27.a and 27.b for Table 3.7-2 are consistent with other relays specified in Surry TS Table 3.7-2 for loss of power instrumentation. Specifically, the required time frames in the proposed Operator Actions 27.a and 27.b are the same as the required time frames in the existing Operator Actions 26.a and 26.b for undervoltage and degraded voltage.

Regarding Operator Action 27.c, the completion time is revised from 90 days to 72 hours. In addition, the terminal action for Operator Action 27 is revised to state "If the conditions are not satisfied, restore the protection function within 7 days or be in at least HOT SHUTDOWN within the next 6 hours and in COLD SHUTDOWN within the following 30 hours." These revisions align the proposed Operator Action 27 completion times with the existing requirements in Operator Action 26 for undervoltage and degraded voltage. The terminal action for Operator Action 26 states "If the required conditions are not satisfied, declare the associated EDG inoperable." The Surry TS 3.16.B.1.a.3 allowed outage time for an inoperable emergency diesel generator (EDG) is 7 days. Thus, the 7-day completion time for the terminal action in the proposed Operator Action 27 parallels the existing requirements in Operator Action 26 for undervoltage and degraded voltage. It should be noted that a 7-day completion time in the terminal action for the proposed Operator Action 27 is more appropriate than declaring the associated EDG inoperable, since inoperability of the open phase protection function does not cause EDG inoperability. Thus, if the open phase protection function cannot be performed, the EDG can still perform its intended safety function in the event of an undervoltage or degraded voltage condition. As shown in the logic diagram provided in Attachment 2 to the January 16, 2018 letter, the open phase protection scheme ties into the existing undervoltage protection scheme; however, inoperability of the open phase protection function does not render the undervoltage/degraded voltage protection scheme inoperable. In summary, the 7-day terminal action in Operator Action 27 to restore the open phase protection function, together with the once per 24 hours verification that an open phase condition does not exist specified in Operator Action 27.c, minimizes the time that an emergency bus is vulnerable to an OPC.

The revised marked-up page TS 3.7-24a and the revised proposed page with the revised Operator Action 27 are provided in Attachments 2 and 3, respectively. The revisions in Operator Action 27.c and in the terminal action for Operator Action 27 are designated by a double revision bar.

RAI No.8 Clarification Request:

The NRC requested clarification regarding when the detection of an OPC would be indicated in the Main Control Room with respect to the OPC Basler relay setting.

Dominion Response:

A detailed description of the negative sequence voltage relay scheme was provided in the original response to RAI No. 4 and in the associated logic diagram provided in Dominion Energy Virginia's January 16, 2018 letter. As noted therein, the Surry open phase analyses indicate that a relay alarm setpoint separate from the relay trip setpoint is not warranted. This is because an alarm setpoint chosen at a point lower than the Basler BE1-47N relays' trip setpoint (< 6%) would be reached nearly simultaneously or in a period of time too short to permit operators to react and take compensatory actions.

When an OPC is sensed and protection of the emergency bus is actuated, an overhead annunciator in the Main Control Room is illuminated as is described in the response to RAI No. 4. If an open phase overhead annunciator is received, operators will check the bus voltage imbalance and verify the associated EDG has started and loaded as required. Operators will also attempt to determine the cause of the open phase by checking the switchyard status panel and checking the overhead bus work at the RSSTs and switchyard transformers TX-1, TX-2, and TX-4.

In summary, actuation of the open phase protection scheme for any given emergency bus requires the following events to be true:

- A voltage imbalance greater than 6% has been sensed by two-out-of-three negative sequence relays
- The protection scheme is not blocked due to a failed or degraded 4kV bus PT
- The emergency bus is being fed from the normal supply breaker

Once the above conditions are met for an emergency bus, an auxiliary relay is energized. The auxiliary relay takes protective actions and actuates an overhead annunciator in the Main Control Room for the unit associated with the respective bus. The annunciator is only activated once the 6% setting has been reached. To confirm, the safety-related open phase scheme does not have a separate setting for annunciation only purposes.

Attachment 2

REVISED MARKED-UP PROPOSED TECHNICAL SPECIFICATIONS PAGE

**Virginia Electric and Power Company
(Dominion Energy Virginia)
Surry Station Units 1 and 2**

Insert A

TABLES 3.7-2 ANDS 3.7-3 (Continued)

TABLE NOTATIONS

ACTION 27. With the number of OPERABLE channels less than the Total Number of Channels, the negative sequence voltage (open phase) protection function may be considered OPERABLE provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 72 hours.

   Note: Action 27.a does not apply if the negative sequence voltage (open phase) protection function cannot be performed.

b. The Minimum OPERABLE Channels requirement is met; however, the inoperable channel may be bypassed for up to 12 hours for surveillance testing of other channels per Specification 4.1.

c. If the negative sequence voltage (open phase) protection function cannot be performed (e.g., the Potential Transformer Blocking Device is tripped), the negative sequence voltage (open phase) protection function does not have to be declared inoperable provided verification is performed at least once per 24 hours that an open phase condition does not exist on the primary side of transformer TX-2, transformer TX-4, and the Reserve Station Service Transformers, as well as the Unit 1/Unit 2 Main Step-up Transformers when power is supplied by the dependable alternate source. The negative sequence voltage (open phase) protection function shall be ~~returned to service within 90 days.~~ restored within 72 hours.

If the conditions are not satisfied, restore the protection function within 7 days or be in at least HOT SHUTDOWN within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

Attachment 3

REVISED PROPOSED TECHNICAL SPECIFICATIONS PAGE

**Virginia Electric and Power Company
(Dominion Energy Virginia)
Surry Station Units 1 and 2**

TABLES 3.7-2 ANDS 3.7-3 (Continued)

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c. If the negative sequence voltage (open phase) protection function cannot be performed (e.g., the Potential Transformer Blocking Device is tripped), the negative sequence voltage (open phase) protection function does not have to be declared inoperable provided verification is performed at least once per 24 hours that an open phase condition does not exist on the primary side of transformer TX-2, transformer TX-4, and the Reserve Station Service Transformers, as well as the Unit l/Unit 2 Main Step-up Transformers when power is supplied by the dependable alternate source. The negative sequence voltage (open phase) protection function shall be restored within 72 hours.

If the conditions are not satisfied, restore the protection function within 7 days or be in at least HOT SHUTDOWN within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.