VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

May 24, 2019 10CFR50.90

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

Serial No. 19-210
NAPS/DPM R0'
Docket Nos. 50-338/339
License Nos. NPF-4/7

VIRGINIA ELECTRIC AND POWER COMPANY
NORTH ANNA POWER STATION UNITS 1 AND 2
PROPOSED LICENSE AMENDMENT REQUEST
OPEN PHASE PROTECTION PER NRC BULLETIN 2012-01
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

By letter dated April 30, 2018 (Serial No. 18-072), Virginia Electric and Power Company (Dominion Energy Virginia) submitted a license amendment request (LAR) to add operability requirements, required actions, and surveillance requirements (SR) to the Technical Specifications (TS) for the 4160V emergency bus negative sequence voltage (open phase) protection function.

In a March 1, 2019 e-mail from Mr. Randy Hall (NRC) to Mr. Craig Sly (Dominion Energy Virginia), the NRC technical staff requested additional information regarding the proposed LAR. Dominion's response to these requests for additional information (RAIs) is provided in Attachment 1 to this letter.

In addition to Dominion's response to the RAIs, the following information is provided in the Attachments to this letter:

- Attachment 2 provides the discussion of a proposed administrative note to TS SR 3.3.5.4
- Attachment 3 provides marked-up Technical Specifications pages
- Attachment 4 provides proposed Technical Specifications pages
- Attachment 5 provides drawings illustrating the connection of PT fuses, BE1-47N relays, and the ABB-60 relay for the Unit 1 H bus
- Attachment 6 provides one-line diagrams highlighting the power feed from the transformers/switchyard to the safety related buses
- Attachment 7 provides proposed UFSAR Revision for Open Phase Protection per NRC Bulletin 2012-01
- Attachment 8 provides the Logic Diagram for the Negative Sequence Voltage Relay Scheme
- Attachment 9 provides the Visual Representation for the Response to RAI-EEOB-15

The addition of the administrative note in TS SR 3.3.5.4 was discussed with Mr. Randy Hall and other NRC staff during the RAI clarification phone call that was held on April 16, 2019.

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NRR

The information provided in this letter does not affect the conclusions of the significant hazards consideration or the environmental assessment included in the April 30, 2018 LAR.

Should you have any questions or require additional information, please contact Ms. Diane E. Aitken at (804) 273-2694.

Respectfully,

Mark D. Sartain
Vice President Nuclear Engineering and Fleet Support

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO)

The foregoing document was acknowledged before me, in and for the County and Commonwealth aforesaid, today by Mr. Mark D. Sartain, who is Vice President – Nuclear Engineering and Fleet Support, 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 24th day of May, 2019.

My Commission Expires: March 31, 2022

Diane E Aitken
Notary Public

DIANE E. AITKEN
NOTARY PUBLIC
REG. #7763114
COMMONWEALTH OF VIRGINIA
MY COMMISSION EXPIRES MARCH 31, 2022

Commitments contained in this letter: None

Attachments:

1. Response to NRC Request for Additional Information Regarding the Proposed License Amendment Request - Open Phase Protection per NRC Bulletin 2012-01
2. Discussion of Proposed Administrative Note to TS SR 3.3.5.4
3. Marked-up Technical Specifications pages
4. Proposed a Technical Specifications pages
5. Drawings Illustrating the Connection of PT Fuses, BE1-47N Relays, and the ABB-60 Relay for the Unit 1 H Bus
6. One-line Diagrams Highlighting the Power Feed from the Transformers/Switchyard to the Safety Related Buses
7. Proposed UFSAR Revision for Open Phase Protection per NRC Bulletin 2012-01
8. Logic Diagram for Negative Sequence Voltage Relay Scheme

9. Visual Representation for the Response to RAI-EEOB-15

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NRC Senior Resident Inspector
North Anna Power Station

Attachment 1

Response to NRC Request for Additional Information
Regarding the
Proposed License Amendment Request
Open Phase Protection per NRC Bulletin 2012-01

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

RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION
NORTH ANNA POWER STATION UNITS 1 AND 2

By letter dated April 30, 2018 (Serial No. 18-072), 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.

In a March 1, 2019 e-mail from Mr. Randy Hall (NRC Project Manager) to Mr. Craig Sly (Dominion Energy Virginia Corporate Regulatory Affairs), the NRC technical staff requested additional information regarding the proposed LAR. The request for additional information (RAI) and Dominion's response are provided below.

NRC Comment: Regulatory Requirements and Guidance Documents

Title 10 of the Code of Federal Regulations (10 CFR) Part 50.36(c)(2), "Limiting conditions for operation," provides the requirement for the establishment of TS limiting conditions for operation (LCO). Paragraph 50.36(c)(2)(ii) requires that a TS LCO of a nuclear reactor be established for each item meeting one or more of the criteria listed. Criterion 3 applies to this LAR, which states: "A structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a design basis accident [DBA] or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier."

10 CFR Part 50.36(c)(3), "Surveillance requirements," states, "Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met."

RAI-EEOB-1:

*In the LAR, Attachment 2, the licensee proposed to revise SR 3.3.5.1 as follows [change is shown in **BOLD** below]:*

SR 3.3.5.1 ------------------------------NOTE--------------------------------
Verification of setpoint is not required.
----
*Perform TADOT for LCO 3.3.5.a and LCO 3.3.5.b **UV/DV** Functions.*

Please clarify whether UV/DV abbreviations have been defined in the TS elsewhere. If not, please provide the description of the abbreviation "UV/DV" In TS.

Dominion Response:

The UV/DV abbreviations have not been defined in the TS elsewhere. SR 3.3.5.1 has been revised to remove the UV/DV abbreviation. Marked-up and proposed TS pages for SR 3.3.5.1 are provided in Attachments 3 and 4, respectively.

RAI-EEOB-2:

In the LAR, Attachment 1, Page 5, the licensee stated:

> *While many OPCs would be addressed by the existing UV relays, some consequential OPCs are not readily detectable by the existing station electrical protection scheme at North Anna Units 1 and 2.*

Please clarify what is meant by "consequential" in the above sentence.

Dominion Response:

North Anna considers consequential OPCs as OPC events that result in either a trip of, or damage to, ESF equipment prior to the equipment being able to perform its design function.

RAI-EEOB-3:

In the LAR, Attachment 1, Page 15, the licensee stated:

> *The negative sequence relay [BE1-47N] includes an inverse timing characteristic feature that is adjustable from 01 to 99 [time dial] in increments of 1. The timing is based on the percent difference from the nominal system voltage. The calculated results show that with a time dial setting of 10.0, the negative sequence voltage relay was secure (i.e., would not issue an alarm) for the simulated unbalanced faults on the medium-voltage and low-voltage systems. The time dial setting of 10.0 provides sufficient time to allow existing overcurrent relaying to trip on the unbalanced fault condition.*

Please demonstrate that the BE1-47N relay time coordination with downstream protective devices is bounding (a sample calculation may be useful in this response).

Please explain why the time dial setting of the BE1-47N relay does not need to be specified in TS.

Dominion Response:

A calculation has been performed to compare the BE1-47N relay performance at a time dial of 10 against existing overcurrent trip times of ESF equipment. Results of the calculation indicate that the OPC protection will coordinate with existing overcurrent devices.

No coordination with existing Under Voltage or Degraded Voltage is required. Actuation of the OPC protection (provided by the BE1-47N relays), Under Voltage protection, or Degraded Voltage protection, will separate the ESF bus from the degraded power source.

The BE1-47N relays operate with an inverse time characteristic, which results in a range of time delays for OPC events. Inclusion of the allowable values for the full range of time delays would not be practical. The North Anna Technical Requirements Manual is being revised to incorporate the setpoint for the BE1-47N relay. The setpoint includes the time dial setting.

RAI-EEOB-4:

In the LAR, Attachment 1, Page 17, the licensee stated:

> *A feature that blocks actuation of the voltage unbalance (open phase) protection function is also included in the logic scheme. This feature enhances the reliability of the protection system and prevents the protection scheme from automatically starting and loading an EDG in the event of a failed fuse on a PT or failed PT. To achieve this feature, one ASEA Brown Boveri (ABB) 60 relay will be installed per bus in the new voltage unbalance circuit.*
>
> *The ABB-60 balance relay is a differential voltage monitoring relay. It receives two different voltage source inputs and compares them to each other. When the voltage of one input changes with respect to the other beyond the setpoint, the relay will energize, and only its set of contacts will change state.*
>
> *A Cutler Hammer ARD relay will be installed downstream of the ABB-60 relay. One output from the ARD relay will be used to block the negative sequence two-out-of-three circuits from energizing. This relay will also*

send a signal to an existing spare annunciator window to indicate a 4KV PT fuse is blown.

Please provide the connection/schematic diagrams(s) illustrating the connection of PT fuses, BE1-47N and ABB-60 relays, as described above, for one of the 4160 V safety-related busses.

Dominion Response:

The portions of the station drawings which illustrate the connection of PT fuses, BE1-47N relays, and ABB-60 relay for Unit 1 H bus are provided in Attachment 5.

RAI-EEOB-5:

In the LAR, Attachment 1, Page 10, the licensee considered open phase conditions at the following locations:

Single open phase without a ground connection
Single open phase with a 350 ohm grounded connection
Single open phase with a solid grounded connection

Please describe whether the 350 ohm grounded connection represents a high impedance ground fault connection, as mentioned in NRC Bulletin 2012-01, and how this value was calculated

Dominion Response:

The total fault impedance of a high resistance fault was calculated based on an empirical model as discussed in the Surry Open Phase Condition Detection Analysis calculation and IEEE paper, "Typical Expected Values of the Fault Resistance in Power Systems." Using the most conservative method discussed in the IEEE paper, a total fault impedance of 173.4 ohms was calculated. This value was doubled to 346.8 ohms and rounded to 350 ohms for use in North Anna's calculation.

RAI-EEOB-6:

In the LAR, Attachment 1, Page 10-11, the licensee stated that analysis was performed for OPCs at the following locations:

High side terminals of the Switchyard Transformer TX-1
High side terminals of the Switchyard Transformer TX-2
High side terminals of the Switchyard Transformer TX-3
High side terminals of the RSST A Transformer
High side terminals of the RSST B Transformer
High side terminals of the RSST C Transformer
High side terminals of the Unit 1 Generator (Main) Step-up Transformer (GSU-1)
High side terminals of the Unit 2 Generator (Main) Step-up Transformer (GSU-2)

Please provide a justification for why open phase conditions were not considered on the low side of above transformers, or not considered credible.

Dominion Response:

For the Switchyard Transformers, the low side of transformers TX-1, TX-2, and TX-3 equate to the high side of the RSSTs. It is expected that the analysis results in these cases would be similar or equivalent to those for the high side of the RSSTs.

For the RSSTs, any OPC event on the low side of the RSSTs trips the existing Under Voltage relays. In these cases, OPC protection would not be required. This was validated in EMTP-RV when developing case studies.

For the GSUs, the low side of the GSUs is terminated to a rigid isophase bus, so an OPC is not considered credible.

RAI-EEOB-7:

In the LAR, Attachment 1, Page 11, the licensee provided a description of various generating conditions and loading conditions (and large motor starts), considered for performing the OPC analysis.

The relationships between various generating conditions and loading conditions considered are not clear to the NRC staff. For each generating condition, please list the corresponding loading conditions considered. Also, explain how for each of the generating and loading conditions considered, the large motor start scenarios were also considered.

Dominion Response:

A list of conditions modeled for performing the OPC analysis for the BE1-47N relay is included in Attachments 1 & 2 of the North Anna Open Phase Analysis Calculation. All combinations of loading conditions and generating conditions were considered with and without a SI/CDA signal or large motor start. Reactor Coolant Pump motor start was the large motor start chosen for offline cases and a tandem Main Feedwater motor start was the large motor start chosen for online cases. These motor cases were selected based on the most severe impact on the electrical system.

The following chart provides examples of plant configurations coincident with the OPC event:

Generating Condition	**Bus Loading**	**SI/CDA Initiation**	**Large Motor Start**
Offline	Minimum Loading	No	No
Offline	Minimum Loading	No	Yes
Offline	Minimum Loading	Yes	No
Offline	Normal Loading	No	No
Offline	Normal Loading	No	Yes
Offline	Normal Loading	Yes	No
Online	Minimum Loading	No	No
Online	Minimum Loading	No	Yes
Online	Minimum Loading	Yes	No
Online	Normal Loading	No	No
Online	Normal Loading	No	Yes
Online	Normal Loading	Yes	No

RAI-EEOB-8:

In the LAR, Attachment 1, Page 13, the licensee stated:

> *For cases where the voltage unbalance is greater than 5%, the results indicate that the BE1- 47N relays trip and isolate the motor loads before the integrated ($I^2 \times t$)[sic] values reach 20 pu [per unit] and before the motor load's associated overcurrent relay trips (when applicable).*

Please describe the relationship between the percentage voltage unbalance and negative sequence current. Quantify the time duration for which the motor may be operated from the OPC source before the negative sequence current heating capability of the motor is exhausted, and before the motor associated overcurrent trips (A sample calculation may be useful in this response).

Dominion Response:

Continuous duty motors are susceptible to additional heating during an open phase condition due to negative sequence current. Induction motors have a withstand capability against unbalanced voltages which is calculated using an integrated per-unit negative sequence current (I_2) squared times time (t) in seconds ($I_2^2 \times t$). An evaluation performed in the North Anna Open Phase Analysis Calculation determined that a conservative value of 20 pu (40pu/2 motor starts) should be used to ensure all motors have enough thermal capability to perform their design functions.

The EMTP-RV simulations conservatively do not include the effect of motor cooling. Continuous duty induction motors are capable of continuous operation under low levels of voltage unbalance. According to NEMA MG-1, for a voltage unbalance between 1% and 5% (percent of motor nameplate voltage), the motor horsepower should be de-rated to account for the additional heating. Operation of the motor with a voltage unbalance above 5% is not recommended. Therefore, for a voltage unbalance greater than 5%, the BE1-47N relays should isolate the motor loads from the OPC condition prior to the $I_2^2 \times t$ value reaching 20 pu.

To validate this condition was met for the BE1-47N relays, a model was created in EMTP-RV to calculate the time until the $I_2^2 \times t$ value for each monitored motor reached 20 pu. This value was compared to the trip time of the BE1-47N relay for each event modeled.

RAI-EEOB-9

In the LAR, Attachment 1, Page 13, the licensee stated:

> *The BE1-47N relays did not actuate for many ungrounded open phase events on the high voltage side of switchyard transformers TX-1 and TX-2. For these conditions, the analysis determined that thermal damage may occur to the Auxiliary Feedwater (AFW) Pump Motors and Inside Recirculation Spray (ISRS) Pump Motors if they are operated continuously under accident loading conditions. For these cases, the Alstom open phase detection relays will detect the open phase event and initiate a trip of its associated transformer within 5 seconds to provide protection to the downstream loads and to be within the time frames considered in the accident analysis.*

Please confirm that the non-Class 1E Alstom Open Phase detection/protection at switchyard transformers TX-1 and TX-2 is not in the scope of this LAR.

Dominion Response:

Dominion confirms that the non-Class 1E Alstom Open Phase detection/protection at switchyard transformers TX-1 and TX-2 is not in the scope of this LAR.

RAI-EEOB-10

In the LAR, Attachment 1, Page 13-14, the licensee stated:

> *BE1-47N relays did not actuate for ungrounded open phase events on the high voltage side of GSU 1 and GSU 2 when Class 1E Bus is aligned and Units are offline. For these conditions, additional analysis was performed to determine if thermal damage may occur to the AFW Pump Motors and ISRS Pump Motors if they are operated continuously under accident loading conditions. Further analysis documents that the AFW and ISRS pump motor insulation will be capable of performing their design function on the most limiting case. Therefore no additional protection is required for this condition.*

Please clarify in the first sentence, whether the words "Units are offline" should actually be "after a Unit is tripped." Please provide a more detailed description of the analysis described above. (A sample calculation may be useful in this response).

Dominion Response:

The OPC events on the high side of the GSUs were evaluated with the unit already offline. When the Main Generator is online, an OPC on the high side of its associated GSU is expected to actuate the generator's negative sequence current protection, which will trip the unit. For Unit 1, the resulting configuration is equivalent to 0% backfeed operation, which is evaluated. For Unit 2, the resulting configuration will isolate the OPC from the station.

RAI-EEOB-11

In the LAR, Attachment 1, Page 15, the licensee provided a Table which summarizes the minimum and maximum Negative Sequence Voltages calculated at each of safety related buses (1H, 1J, 2H, and 2J) for open phase locations at TX-1, TX-2, TX-3, RSST-A, RSST-B, RSST-C, GSU 1-1H, GSU 1-2J, GSU 2-1J, and GSU 2-2H.

Please explain why two open phase locations have been considered for each GSU (e.g., GSU 1-1H, GSU 1-2J), whereas according to the LAR, Attachment 1, Page 11, only one open phase location has been considered on high side of each GSU. For the various operating conditions, please provide one-line diagrams highlighting the power feed from the above transformers/switchyard to the safety related buses.

Dominion Response:

One location is considered for each GSU (OPC on the high side of the GSUs). Two plant configurations are considered based on possible Station Service Bus to Emergency Bus cross-tie configurations. The one-line diagrams highlighting the power feed from the above transformers/switchyard to the safety related buses is provided in Attachment 6.

RAI-EEOB-12

In the LAR, Attachment 1, Page 40, the licensee stated:

> *A UFSAR change request has been initiated to revise the UFSAR to describe the voltage unbalance analysis and detection/protection scheme implemented by this modification.*

For any portions of the UFSAR change that are within the scope of this LAR, please provide a proposed markup of the UFSAR change.

Dominion Response:

Proposed markup of the North Anna UFSAR within scope of this LAR is provided in Attachment 7.

RAI-EEOB-13

In the LAR, Attachment 1, Page 20, the licensee stated:

> *For single ungrounded open phase events on the high side of transformers GSU 1 and GSU 2, there is insufficient negative sequence voltage to actuate the BE1-47N relays. However the negative sequence voltage is greater than 1% when the open phase event is coincident with a pre-existing 3% switchyard unbalance.*

Please provide the basis for the pre-existing 3% switchyard unbalance assumption.

Dominion Response:

ANSI C84.1-2001 discusses how electric supply systems should be designed and operated to limit maximum voltage unbalance to 3%. This value was used in the North Anna Open Phase Analysis Calculation to represent the maximum expected switchyard unbalance seen by the station prior to the OPC condition.

RAI-EEOB-14

Please provide a logic diagram and provide a discussion that clearly demonstrate the negative sequence voltage relay scheme (detection, alarm, and protection), including the feature that blocks actuation of the negative sequence voltage (open phase) protection using the ABB 60 (voltage balance) relay. Also discuss how that scheme interfaces with the existing undervoltage (UV) and degraded voltage (DV) relay protection schemes, which trip the offsite power circuits at the ESF bus level and initiate the EDG starts.

Dominion Response:

A logic diagram is provided in Attachment 8 to illustrate the negative sequence voltage relay scheme and how it interfaces with the existing undervoltage relay protection scheme. The logic diagram provided is for Emergency Bus 1H; Emergency Buses 1J, 2H, and 2J are similar. A description of the scheme is provided below.

The open phase protection system is being implemented on each of the four Emergency Buses. The system consists of three Basler BE1-47N negative sequence relays, with each relay detecting all three phases, connected to each of the emergency bus (1H, 1J, 2H, and 2J) potential transformers (PTs). The three negative sequence relays each contain an auxiliary relay, which is used to develop a two-out-of-three logic scheme. This requires two or more relays to sense a voltage imbalance greater than 4% (i.e., an OPC) to initiate protection of the emergency bus.

The open phase detection scheme is inserted into the existing undervoltage protection circuit for each Emergency Bus. The initiation of an undervoltage or open phase actuation, requires that the emergency bus is being fed from an off-site power source. The parallel input (undervoltage and open phase) feeds an additional parallel circuit containing 52 contacts of each source of offsite power.. To include this logic in the protection scheme, wiring is installed to 52 contacts at the respective breakers that supply offsite power to the emergency bus.

Additionally, a feature that blocks the open phase system protection actuation is also included in the logic scheme. This feature enhances the reliability of the protection system and prevents the protection scheme from actuating in the event of a failed or degraded 4kV bus PT or blown PT fuse. To achieve this feature, one ABB 60 voltage balance relay is installed per bus. The relay compares 4kV Emergency Bus PT voltages with 480V Emergency Bus PT voltages. Relay contact outputs specific to each voltage source actuate if the given source lowers to the voltage difference setpoint. The 480V PT source output contact is not used; however, the relay may activate that contact for a 480V bus transient, fault, or other event on the 480V system that causes that voltage input to the relay to reach the setpoint. If a 4kV PT failure occurs, the relay senses a voltage imbalance and opens an auxiliary relay contact which blocks the open phase protection system. One relay contact is also used to operate a white light on the front of the relay panel that will alert operators that open phase protection is disabled.

In summary, actuation of the open phase protection scheme for any given Emergency Bus requires the following conditions to be present:

- A voltage imbalance greater than 4% 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, and
- The Emergency Bus is being fed from the normal or alternate offsite supply breaker.

When the above conditions exist for an emergency bus, an auxiliary relay is energized. The auxiliary relay actuates an overhead annunciator in the Main Control Room and will also close a contact, thereby energizing an existing undervoltage protection auxiliary relay for the associated bus. This auxiliary relay trips the bus normal supply breaker or alternate supply breaker, starts the EDG, and transfers following the same process as the undervoltage/degraded voltage protection scheme. Tripping the emergency bus normal or alternate supply breaker is an adequate response to an open phase event, since it separates safety related and important to safety loads from the degraded offsite source and provides these loads with a reliable source of power from an EDG.

RAI-EEOB-15

In the LAR, Attachment 1, Page 16, the licensee stated:

> *For open phase conditions on Transformers TX-3, RSST A, RSST B, and RSST C (Delta-Wye Transformers) the minimum negative sequence voltage on the impacted emergency buses is above the minimum possible setting for the BE1- 47N relay. The minimum observed negative sequence voltage was 12.318V (17.78%), located on Bus 1H for an open phase condition on RSST C.*

Please confirm whether the above negative sequence voltage of 12.318 V (17.78%) can be considered as Analytic Limit for calculating various margins with respect to the nominal 4% pickup setting of the BE1-47N relay.

Dominion Response:

The BE1-47N relays are calculated to always trip at > 3.538V. For OPCs at TX-3 and RSSTs A/B/C, the lowest negative sequence voltage observed is 12.318V, which ensures the OPC is detected. A 4% setpoint was chosen for the BE1-47N relay and calculated to have a ±1.106% maximum uncertainty. The BE1-47N relay may detect the OPC from 2.005V to 3.538V. Voltages below 2.005V will not result in a trip of the BE1-47N relays. A visual representation of this response is provided in Attachment 9.

RAI-EEOB-16

In the LAR, Attachment 1, Page 12-13, the licensee stated:

> *This thermal capability also has to consider that Class 1E motors restart on the EDGs after tripping from the unhealthy source. To account for this motor starting sequence, a total thermal limit ($I^2 \times t$)[sic] of less than or equal to 20 per unit (pu) (40 pu/2 starts) for Class 1E motors during the open phase event concurrent with a LOCA is used as a bounding condition to ensure the motors have enough thermal capability to perform their safety functions.*

Please describe the basis for the assumption "a total thermal limit ($I^2 \times t$) of less than or equal to 20 per unit (pu) (40 pu/2 starts) for Class 1E motors.

Dominion Response:

The basis for using 20 pu as a limit for the $I_2^2 \times t$ thermal capacity is from a Surry calculation, as summarized below:

No standards exist which describe the permissible negative sequence load current operation for induction motors. However, a few guidelines for motors have been suggested as follows:

- An IEEE 1985 IAS paper suggests that $(I_2)^2 t \leq 120$ pu for short-time operation.
- An IEEE 1958 PAS paper suggests $(I_2)^2 t = 40$ pu.
- The Westinghouse protective relaying book indicates, *"No standards have been established for the $I_2^2 t$ short-time capability of a motor, although $I_2^2 t = 40$ pu is regarded as a conservative value."*
- A 1979 technical paper authored by General Electric application engineers, suggested that $(I_2)^2 t$ can be estimated (based on an empirical relationship) using the safe stall (locked rotor) time and inrush current (i.e., LRA) of the motor. *They proposed that $(I_2)^2 t$ capability $\approx (1/3) \times (LRA)^2 \times$ Motor Safe Stall Time.* The table below is developed following this guideline; assuming that the LRA = 6 x FLA, or 6 per unit.

Motor Safe Stall Time (seconds)	$(I_2)^2 t=$
20	240
10	120
7.5	90
5	60
3.33	40

The motor $(I_2)^2 t$ =240, 120, 90, 60, and 40 curves have been plotted with the aid of the ETAP Star Module. If the actual (or estimated) motor safe-stall time and LRA are known, similar $(I_2)^2 t$ curves can be developed for any induction motor. The motor "hot" safe-stall time should be used since the open-phase scenario can occur when the motor is running and operating at or near its rated temperature.

However, for North Anna Power Station, the hot safe-stall time of every motor is not available in existing motor vendor data. Therefore, a conservative value of $(I_2)^2 t = 40$pu was used. This represents a hot safe stall time of 3.33 seconds.

Based on a survey of industry guidelines, the $(I_2)^2t$ heating capability of an induction motor was conservatively assumed to be equal to or greater than 40 pu.

RAI-EICB-1

*In the LAR, the licensee proposed to add new Surveillance Requirements (SR) 3.3.5.3.c, as follows [changes are shown in **BOLD** below]:*

SR 3.3.5.3 --------------------*NOTE*-----------------------------

Negative Sequence Voltage is calculated as a percentage of nominal voltage.

Perform CHANNEL CALIBRATION with Allowable Values as follows:

c. ***Negative Sequence Voltage ≥ 2.894 % and ≤ 5.106 % for LCO 3.3.5.a and LCO 3.3.5.b Functions***

In the LAR, Attachment 1, Page 16, the licensee provided the maximum uncertainty (i.e., the Channel Statistical Allowance, or CSA) for the Basler BE1-47N relay at the 4 kV emergency buses, which was calculated to be ± 1.106% of span. The instruction manual for the Basler BE1-47N Negative Sequence Voltage Relay stated that, "Pickup accuracy is within ± 1 unit of the percent setting of the negative sequence voltage." The LAR indicates that a 4% relay pickup setting, with a time dial setting of 10.0, would be implemented for the relay settings.

The NRC staff notes that a similar license amendment for Surry to modify the plant Technical Specifications to address surveillance requirements for an identical manufacturer and model number negative sequence voltage relay used a 6% relay pickup setting with a ± 2.4% CSA. This LAR specifies a CSA of ± 1.106% for North Anna with identical relays. It is unclear if the small operating margin provided by this CSA sufficiently accounts for all the uncertainties that could lead to spurious trips of the power supply system as a result of routine fluctuations in power conditions.

Please provide a description regarding each of the uncertainties included within the proposed CSA of ± 1.106% of span, such as instrument accuracy, calibration accuracy, drift, etc. The description should demonstrate that the setpoint plus-or-minus the calculated total performance uncertainty would not result in frequent spurious trips.

This information is needed to enable the NRC staff to verify the requirements of 10 CFR 50.36(c)(2) and implementing guidance within Regulatory Guide 1.105 are met regarding the selection of the setpoints and allowable values to protect against an unbalanced voltage potentially leading to an open phase condition.

Dominion Response:

North Anna BE1-47N Channel Statistical Allowance Calculation included the following uncertainties:

- Rack Calibration Accuracy of ±1% (based on BE1-47N pickup uncertainty)
- Process Measurement Uncertainty of ±0.365%. This was determined by taking the PT uncertainty of 0.3% and taking into account phase errors as defined in IEEE C57.13-2016.
- Sensor Measuring and Test Equipment Uncertainty of ±0.3%

The differences between the uncertainty bands at North Anna and Surry can be attributed to the variations in the Process Measurement Uncertainty. This can be explained by the different PT designs and IEEE C57.13 editions used at each station. North Anna used the 2016 edition of IEEE C57.13 and Surry used the 2008 edition of IEEE C57.13.

Attachment 2

Discussion of Proposed Administrative Note to TS SR 3.3.5.4

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

Discussion of Proposed Administrative Note to TS SR 3.3.5.4

The proposed administrative note to TS SR 3.3.5.4 is for clarification purposes only. ESF Response Times are only applicable to under voltage and degraded voltage functions. Negative sequence relays have an inverse time characteristic and the response times will vary depending on the amplitude.

The negative sequence relays are subject to the performance of the Trip Actuating Device Operational Test (TADOT) and channel calibration in accordance with the Surveillance Frequency Control Program

Attachment 3

Marked-up Technical Specifications pages

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

Technical Specification Marked-up Page from Original LAR submittal, dated April 30, 2018

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time not met.	C.1 Enter applicable Condition(s) and Required Action(s) for the associated EDG made inoperable by LOP EDG start instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.5.1	--------------------NOTE------------ Verification of setpoint is not required. ------------------------------- Perform TADOT for LCO 3.3.5.a and LCO 3.3.5.b Functions. Loss of Voltage/Degraded Voltage ~~UV/DV~~	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.2	* See next page for markup	
SR 3.3.5.~~2~~3	** See next page for note markup Perform CHANNEL CALIBRATION with Allowable Values as follows: a. Loss of voltage Allowable Values ≥ 2935 V and ≤ 3225 V with a time delay of 2 ±1 seconds for LCO 3.3.5.a and LCO 3.3.5.b Functions. b. Degraded voltage Allowable Values ≥ 3720 V and ≤ 3772 V with: 1. A time delay of 7.5 ±1.5 seconds with a Safety Injection (SI) signal for LCO 3.3.5.a Function; and 2. A time delay of 56 ±7 seconds without an SI signal for LCO 3.3.5.a and LCO 3.3.5.b Functions. c. Negative Sequence Voltage ≥ 2.894% and ≤ 5.106% for LCO 3.3.5a and LCO 3.3.5b Functions	In accordance with the Surveillance Frequency Control Program

Technical Specification Marked-up Page from Original LAR submittal, dated April 30, 2018

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.5.~~3~~ 4 ***	Verify ESF RESPONSE TIMES are within limit for LCO 3.3.5.a and LCO 3.3.5.b Functions.	In accordance with the Surveillance Frequency Control Program
* SR 3.3.5.2	NOTE Verification of Setpoints not required Perform TADOT for LCO 3.3.5a and LCO 3.3.5b Negative Sequence Relay Functions	In accordance with the Surveillance Frequency Control Program

** SR 3.3.5.3 NOTE

NOTE

Negative Sequence Voltage is calculated as a percentage of nominal voltage.

*** SR 3.3.5.4 NOTE

NOTE

ESF RESPONSE TIMES are only applicable to Loss of Voltage and Degraded Voltage Functions

Attachment 4

Proposed Technical Specifications pages

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

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.5.1	--------------------NOTE---------------- Verification of setpoint is not required. -- Perform TADOT for LCO 3.3.5.a and LCO 3.3.5.b Loss of Voltage/Degraded Voltage Functions.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.2	--------------------NOTE---------------- Verification of setpoint is not required. -- Perform TADOT for LCO 3.3.5.a and LCO 3.3.5.b Negative Sequence Relay Functions.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.3	--------------------NOTE---------------- Negative Sequence Voltage is calculated as a percentage of nominal voltage. -- Perform CHANNEL CALIBRATION with Allowable Values as follows: a. Loss of voltage Allowable Values ≥ 2935 V and ≤ 3225 V with a time delay of 2 ±1 seconds for LCO 3.3.5.a and LCO 3.3.5.b Functions. b. Degraded voltage Allowable Values ≥ 3720 V and ≤ 3772 V with: 1. A time delay of 7.5 ±1.5 seconds with a Safety Injection (SI) signal for LCO 3.3.5.a Function; and 2. A time delay of 56 ±7 seconds without an SI signal for LCO 3.3.5.a and LCO 3.3.5.b Functions. c. Negative Sequence Voltage ≥ 2.894% and ≤ 5.106% for LCO 3.3.5.a and LCO 3.3.5.b Functions.	In accordance with the Surveillance Frequency Control Program

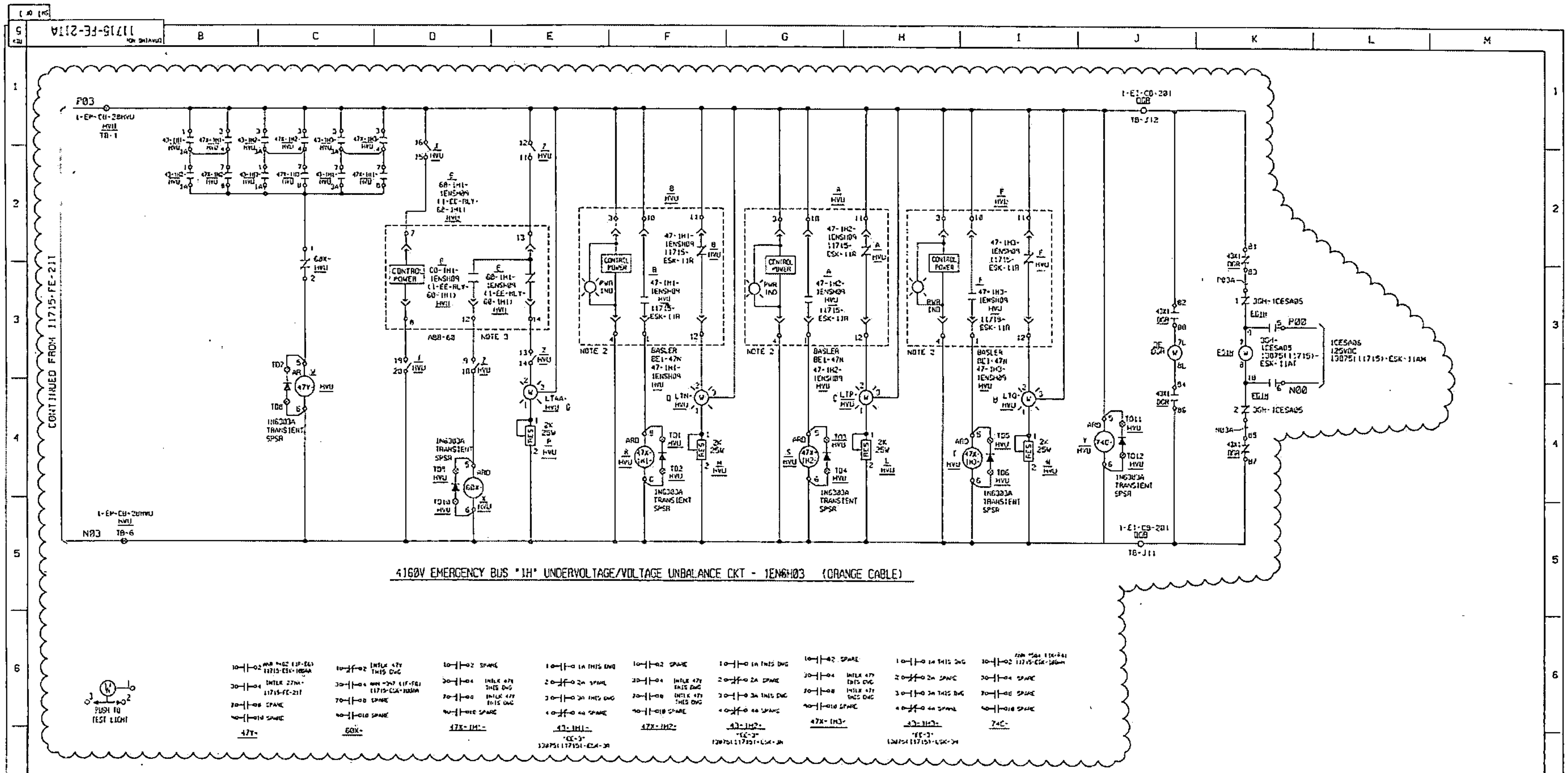
SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
	-------------------NOTE----------------- ESF Response Times are only applicable to Loss of Voltage and Degraded Voltage Functions. --	
SR 3.3.5.4	Verify ESF RESPONSE TIMES are within limit for LCO 3.3.5.a and LCO 3.3.5.b Functions.	In accordance with the Surveillance Frequency Control Program

Attachment 5

Drawings Illustrating the Connection of PT Fuses, BE1-47N Relays, and the ABB-60 Relay for the Unit 1 H Bus

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



NOTES:

1. FOR NOTES AND REFERENCES DRAWINGS SEE 11715-FE-21I
2. FOR TIME TO TRIP CHARACTERISTICS SEE VTM 59-0622-00005
3. CONTACTS CHANGE STATE INSTANTANEOUSLY WHEN THE DIFFERENCE BETWEEN LINE A AND LINE B IS EQUAL OR GREATER THAN THE SETPOINT. THE RELAY CONTACTS RESET IN 1 SECOND AFTER THE CONDITION CLEARS. ONLY THE CONTACTS RELATING TO LINE A ARE USED.

PRIORITY DRAWING

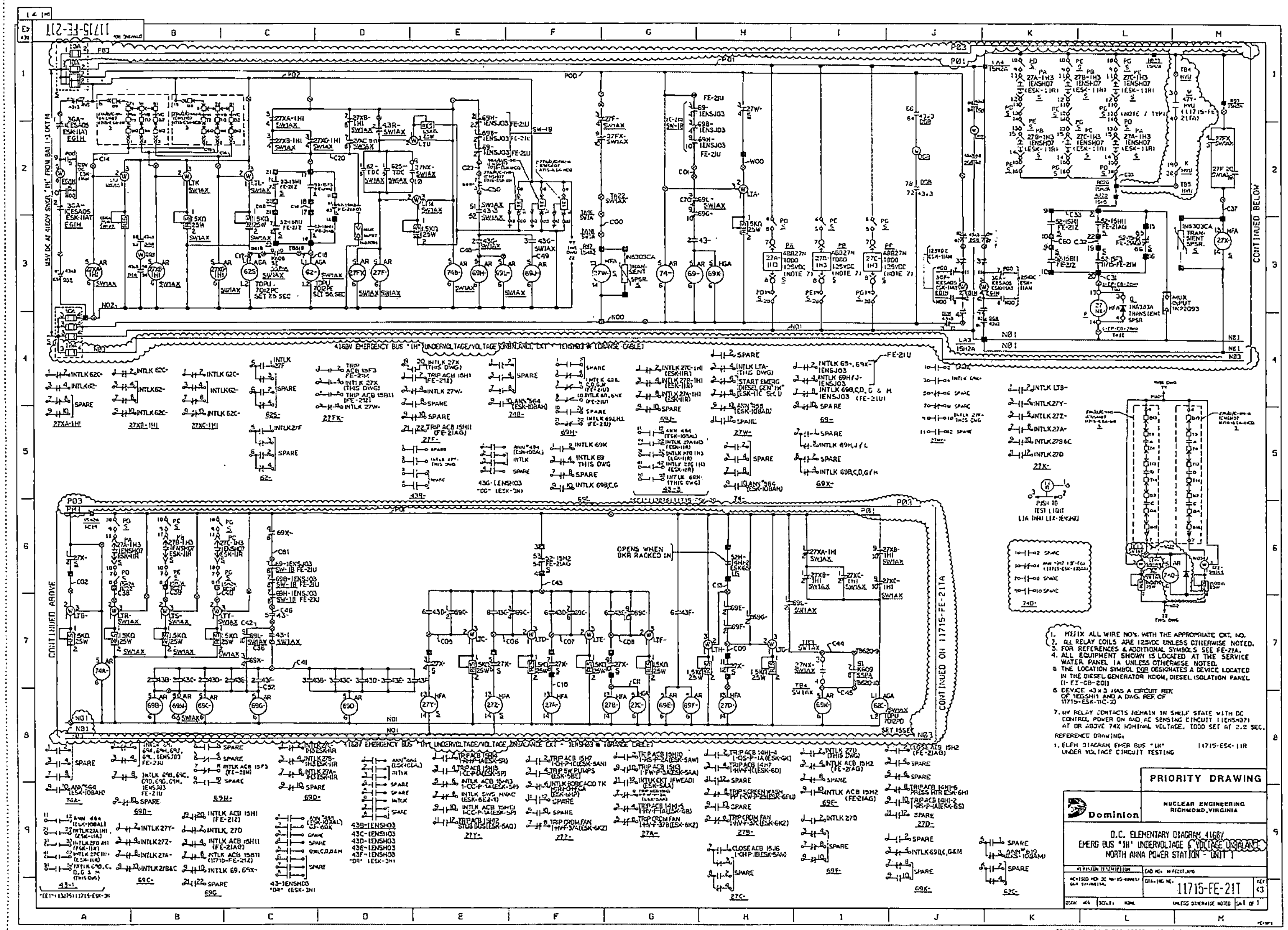
Dominion | NUCLEAR ENGINEERING RICHMOND, VIRGINIA

D.C. ELEMENTARY DIAGRAM 4160V
EMERG BUS "1H" UNDERVOLTAGE
NORTH ANNA POWER STATION - UNIT 1

DRAWING NO. 11715-FE-21TA REV 5

SCALE: NONE

PRIOR TO USING FOR DESIGN WORK CHECK DNIS FOR WORK PENDING



1. PREFIX ALL WIRE NO'S. WITH THE APPROPRIATE CKT. NO.
2. ALL RELAY COILS ARE 125VDC UNLESS OTHERWISE NOTED.
3. FOR REFERENCES & ADDITIONAL SYMBOLS SEE FE-21A.
4. ALL EQUIPMENT SHOWN IS LOCATED AT THE SERVICE WATER PANEL 1A UNLESS OTHERWISE NOTED.
5. THE LOCATION SYMBOL DGP DESIGNATES A DEVICE LOCATED IN THE DIESEL GENERATOR ROOM, DIESEL ISOLATION PANEL (1-EI-CB-201)
6. DEVICE 43×3 HAS A CIRCUIT REF OF 1EGSH11 AND A DWG. REF OF 11715-ESK-11C-10
7. UV RELAY CONTACTS REMAIN IN SHELF STATE WITH DC CONTROL POWER ON AND AC SENSING CIRCUIT (1ENSH07) AT OR ABOVE 74% NOMINAL VOLTAGE. TDDO SET AT 2.0 SEC.

REFERENCE DRAWING:

1. ELEM DIAGRAM EMER BUS "1H" UNDER VOLTAGE CIRCUIT TESTING — 11715-ESK-11R

PRIORITY DRAWING

Dominion

NUCLEAR ENGINEERING
RICHMOND, VIRGINIA

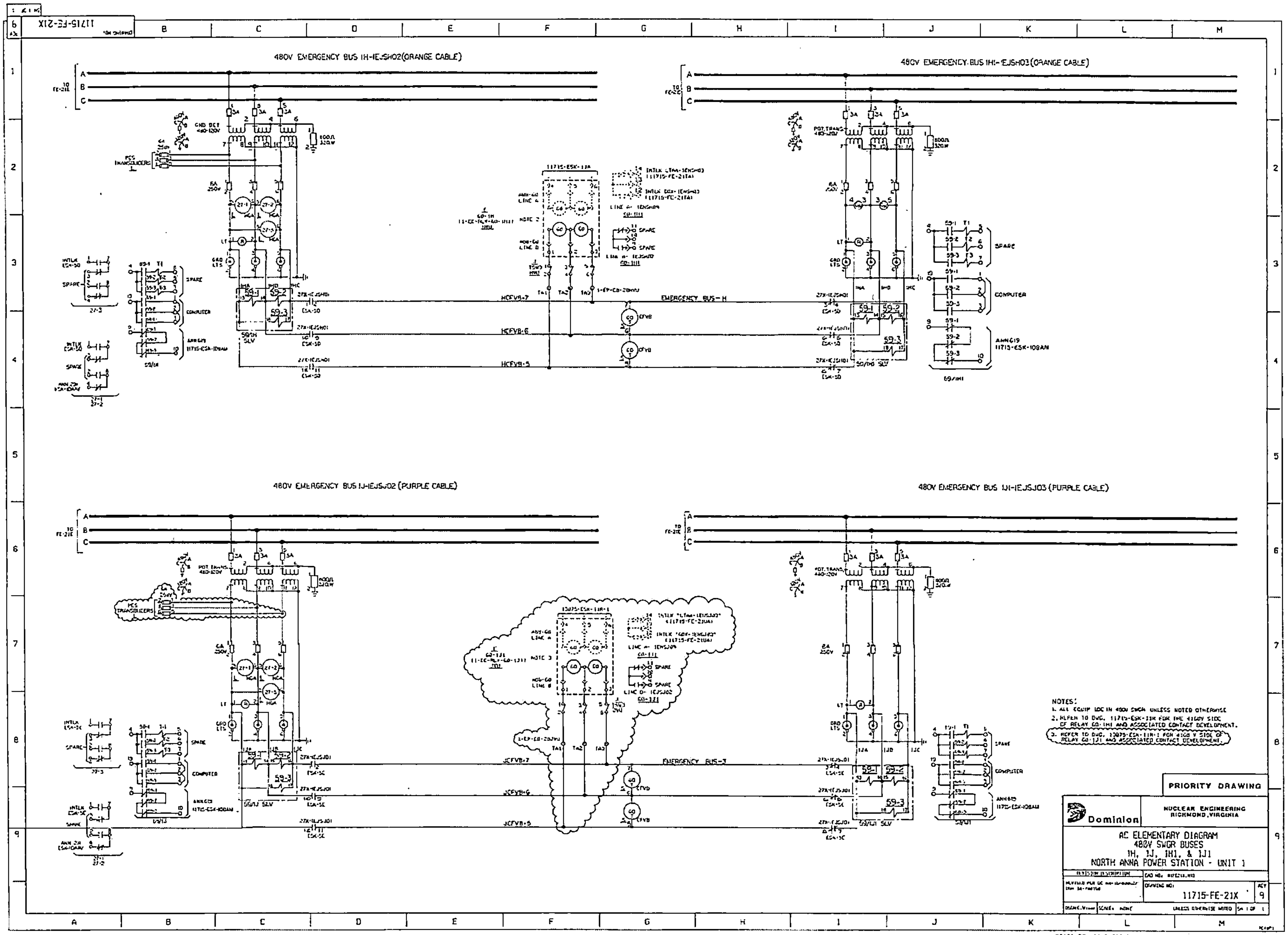
D.C. ELEMENTARY DIAGRAM 4160V
EMERG BUS "1H" UNDERVOLTAGE & VOLTAGE UNBALANCE
NORTH ANNA POWER STATION - UNIT 1

CAD NO: N1FE21T.HYD

DRAWING NO: 11715-FE-21T — REV 43

SH 1 OF 1

PRIOR TO USING FOR DESIGN WORK CHECK DMIS FOR WORK PENDING



NOTES:
1. ALL EQUIP LOC IN 480V SWGR UNLESS NOTED OTHERWISE
2. REFER TO DWG. 11715-ESK-21K FOR THE 4160V SIDE OF RELAY GO-1H1 AND ASSOCIATED CONTACT DEVELOPMENT.
3. REFER TO DWG. 13075-ESK-11R-1 FOR 4160 V SIDE OF RELAY GO-1J1 AND ASSOCIATED CONTACT DEVELOPMENT.

PRIORITY DRAWING

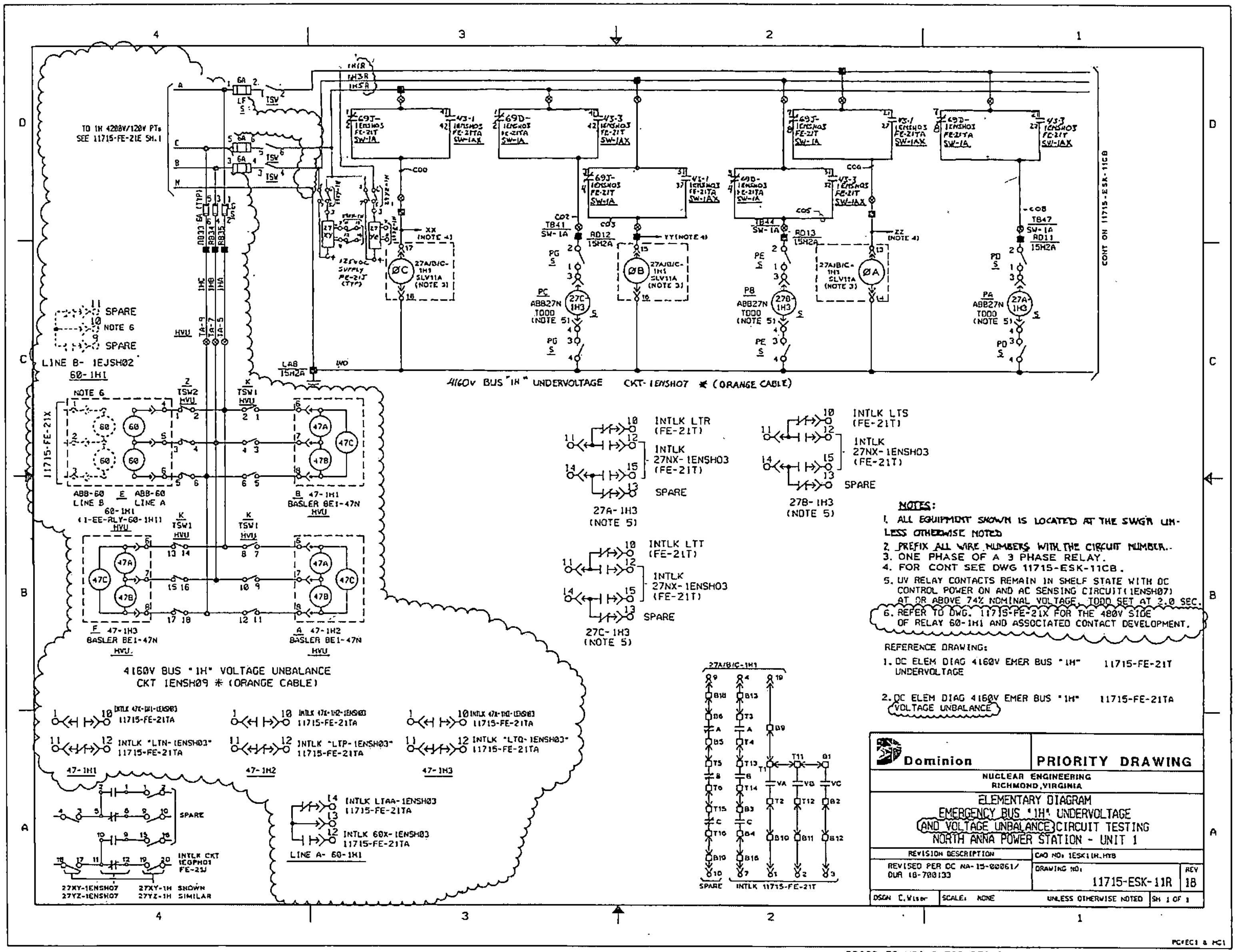
Dominion

NUCLEAR ENGINEERING
RICHMOND, VIRGINIA

AC ELEMENTARY DIAGRAM
480V SWGR BUSES
1H, 1J, 1H1, & 1J1
NORTH ANNA POWER STATION - UNIT 1

DRAWING NO: 11715-FE-21X
REV 9
SCALE: NONE
SH 1 OF 1

PRIOR TO USING FOR DESIGN WORK CHECK DMIS FOR WORK PENDING



NOTES:

1. ALL EQUIPMENT SHOWN IS LOCATED AT THE SWGR UNLESS OTHERWISE NOTED.
2. PREFIX ALL WIRE NUMBERS WITH THE CIRCUIT NUMBER.
3. ONE PHASE OF A 3 PHASE RELAY.
4. FOR CONT SEE DWG 11715-ESK-11CB.
5. UV RELAY CONTACTS REMAIN IN SHELF STATE WITH DC CONTROL POWER ON AND AC SENSING CIRCUIT (1ENSH07) AT OR ABOVE 74% NOMINAL VOLTAGE. TDDO SET AT 2.0 SEC.
6. REFER TO DWG. 11715-FE-21X FOR THE 480V SIDE OF RELAY 60-1H1 AND ASSOCIATED CONTACT DEVELOPMENT.

REFERENCE DRAWING:

1. DC ELEM DIAG 4160V EMER BUS "1H" UNDERVOLTAGE — 11715-FE-21T
2. DC ELEM DIAG 4160V EMER BUS "1H" VOLTAGE UNBALANCE — 11715-FE-21TA

Dominion — PRIORITY DRAWING

NUCLEAR ENGINEERING
RICHMOND, VIRGINIA

ELEMENTARY DIAGRAM
EMERGENCY BUS "1H" UNDERVOLTAGE
AND VOLTAGE UNBALANCE CIRCUIT TESTING
NORTH ANNA POWER STATION - UNIT 1

REVISION DESCRIPTION	CAD NO: 1ESK11R.HYB	
REVISED PER DC NA-15-00061/ DUR 18-700133	DRAWING NO: 11715-ESK-11R	REV 18
DSGN C. Wiser — SCALE: NONE	UNLESS OTHERWISE NOTED	SH 1 OF 1

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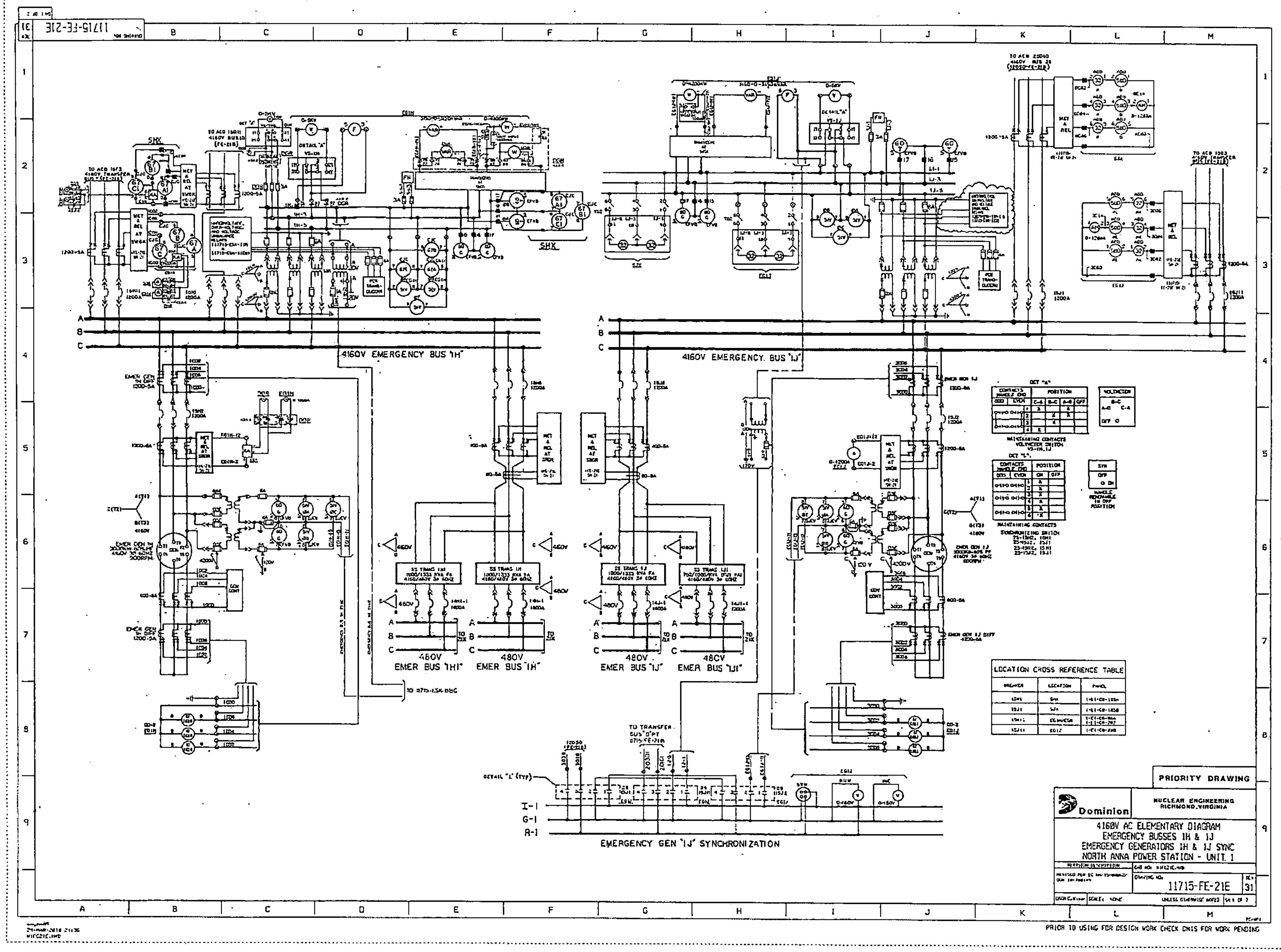
PRIOR TO USING FOR DESIGN WORK CHECK DMIS FOR WORK PENDING

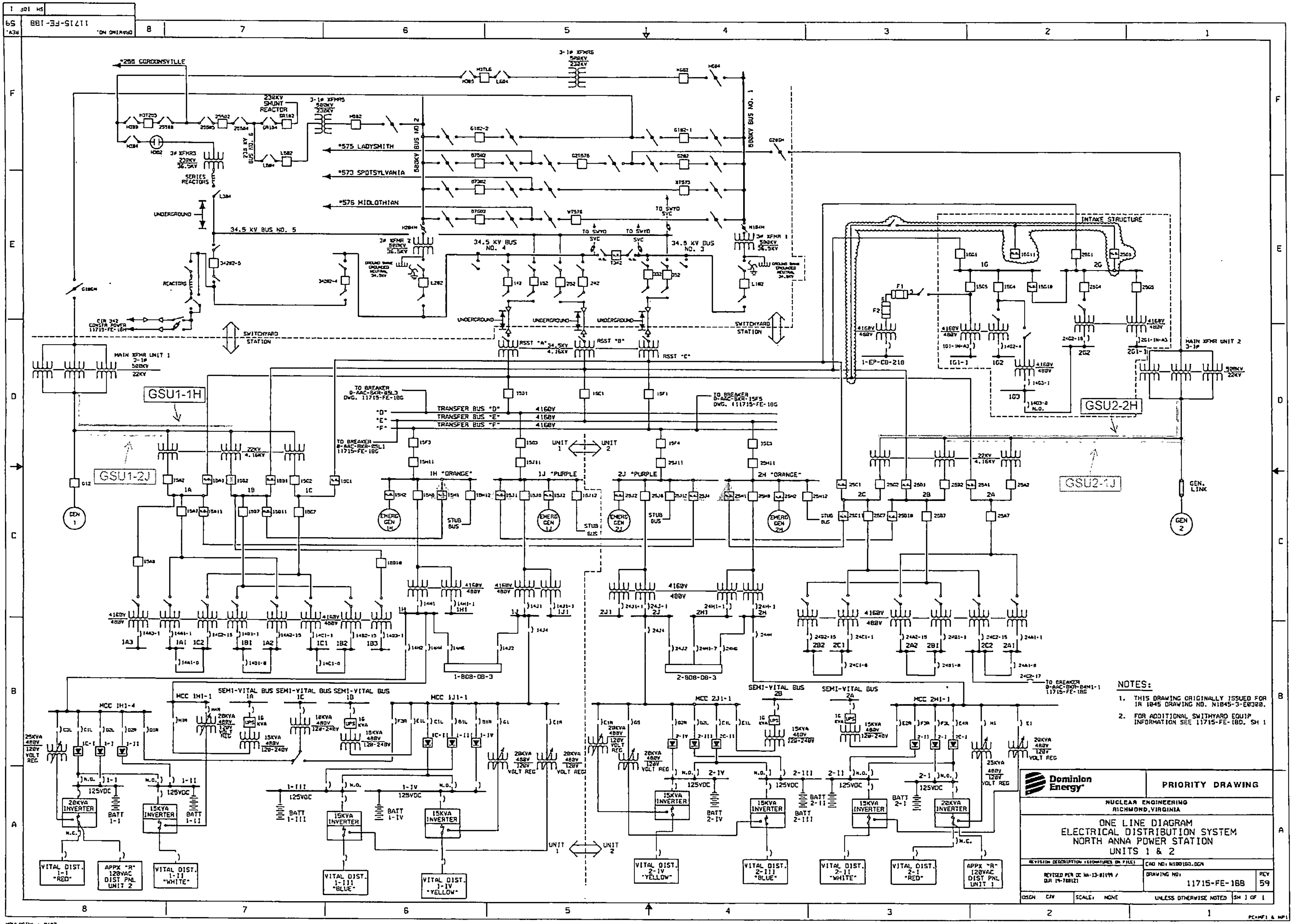


4160V EMERGENCY BUS "1H"
4160V EMERGENCY BUS "1J"
480V EMER BUS "1H1"
480V EMER BUS "1H"
480V EMER BUS "1J"
480V EMER BUS "1J1"
EMERGENCY GEN "1J" SYNCHRONIZATION
LOCATION CROSS REFERENCE TABLE
PRIORITY DRAWING
Dominion
NUCLEAR ENGINEERING
RICHMOND, VIRGINIA
4160V AC ELEMENTARY DIAGRAM
EMERGENCY BUSSES 1H & 1J
EMERGENCY GENERATORS 1H & 1J SYNC
NORTH ANNA POWER STATION - UNIT 1
11715-FE-21E
31
PRIOR TO USING FOR DESIGN WORK CHECK DNIS FOR WORK PENDING

Attachment 6

One-line Diagrams Highlighting the Power Feed from the Transformers/Switchyard to the Safety Related Buses

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



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PRIOR TO USING FOR DESIGN WORK CHECK DMIS FOR WORK PENDING

Attachment 7

Proposed UFSAR Revision for Open Phase Protection per NRC Bulletin 2012-01

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

5. Containment recirculation air coolers—The air coolers cooling water flow is indicated in the control room. The cooling water exit temperatures are provided to the plant computer. The sensors are outside the reactor containment.

6. Sump instrumentation—The containment sump wide range instrumentation consists of redundant level sensors designed to operate in a post accident environment. LT-RS151A-1, LT-RS151A-2, LT-RS151B-1, and LT-RS151B-2 sump wide range level transmitters are qualified in accordance with IEEE Std 323-1974, to meet post accident conditions, including submergence. The indicators are located in the control room.

7.3.1.3.4 Digital Circuitry

The ESF logic racks are discussed in detail in Reference 3. The description includes the considerations and provisions for physical and electrical separation as well as details of the circuitry. Reference 3 also covers certain aspects of on-line test provisions, provisions for test points, considerations for the instrument power source, considerations for accomplishing physical separation, and provisions for ensuring instrument qualification. The outputs from the analog channels are combined into actuation logic as shown in Figure 7.2-5 (T_{avg}), Figure 7.2-6 (pressurizer pressure and water level), Figure 7.2-7 (steam flow, pressure, and differential pressure), Figure 7.2-9 (ESF actuation), and Figure 7.3-1 (auxiliary feedwater).

To facilitate ESF actuation testing, two cabinets (one per train) are provided that enable the operation of safety features actuation devices on a group-by-group basis until the actuation of all devices has been checked. Final actuation testing is discussed in detail in Section 7.3.2.

7.3.1.3.5 Engineered Safety Features Actuation Devices

The outputs of the solid-state logic protection system (the slave relays) are energized to actuate, as are the switchgear and motor control centers for all ESF-actuated devices. The following descriptions and referenced diagrams explain and illustrate the manner in which the engineered safety features are actuated by the ESF actuation signals. Unit protection features and emergency diesel-generator start-up and loading are also described and illustrated. Should an accident occur coincident with a station electrical blackout, the ESF loads are sequenced onto the diesel generators. This loading is discussed in Chapter 8. The design meets the requirements of General Design Criterion 35.

1. Figure 7.3-2 is a general illustration of the relationship of unit trip signals. The interrelation of tripping between the generator, turbine, and reactor is as follows:

    a. A generator trip will result in a turbine trip.

    b. A turbine trip after the generator is on line will result in a generator trip.

    c. A turbine trip at a preset minimum power will result in a reactor trip.

    d. A reactor trip will result in a turbine trip.

2. Figure 7.3-3 illustrates the signal interfaces of ESF actuation and actuated devices. These interfaces are the basis of the ESF system terminology and logic, and the actuation signals are shown in relation to each other as well as the actuated systems.

3. Figures 7.3-4 and 7.3-5 illustrate that there are two paths provided to actuate the ESF-actuated devices: the first, when emergency bus power is not interrupted; the second, when there is a loss of emergency bus power. Should there be a loss of power, the equipment is started sequentially.

4. Figure 7.3-6 illustrates the concepts used to adjust and sequence the loads on diesel generators. The inputs will be combined by the logic circuit as required, to initiate the appropriate sequence and loading of the diesel generator for given accident input conditions. The resultant blocks represent typical actions taken on equipment assigned to the emergency bus. Detailed logic for specific loads is shown in Reference Drawings 11 and 12, and Figures 7.3-5, 7.3-7 and 7.3-8.

5. Reference Drawing 13, Figure 7.3-1, and Figure 7.3-7 illustrate the development of the loss of reserve station service power signal for both Units 1 and 2. Also shown are the resultant actuation of the service water pumps, and the start of auxiliary steam generator feed pumps.

6. Figures 7.3-5 and 7.2-9 illustrate the auto-start signals for an emergency diesel generator. The emergency diesel generator starts whenever the respective emergency bus voltage is less than 74%, whenever the bus voltage drops below 90% and remains there for 60 seconds or longer, or whenever a safety injection actuation signal is initiated. This is described in Section 8.3.1.1.1.

   whenever the bus phase voltage unbalance results in >4% negative sequence voltage (ie open phase condition),

   Also shown in Figure 7.3-5 are the resultants, should the emergency bus voltage continue to decay below 71% nominal. These resultants are the automatic trip of specified loads.

   Also illustrated is the subsequent restoration of voltage to the emergency bus, after the emergency diesel-generator supply breaker is closed. Refer to Reference Drawing 12 (containment depressurization) and Reference Drawing 11 (safety injection) for the subsequent restart of the affected ESF actuation devices.

7. Figure 7.3-8 illustrates the equipment that is tripped on a signal from the containment depressurization actuation (CDA) signal. This is done to remove unnecessary loads from the emergency diesel generators.

8. Figure 7.3-9 is a diagram of the undervoltage signal for the normal station service buses. When voltage drops below 70% on 2/3 station service buses (1A, 1B, or 1C), the reactor is tripped, providing the reactor power level is greater than P-7.

   Undervoltage on the station service bus results in the following:

   a. Main feedwater pump trips.

   b. Reactor coolant pump trips.

b. Depression of the CLOSE push button.

c. Containment isolation signal.

Figure 7.3-2 illustrates and describes the turbine and generator trips.

7.3.1.3.5.3 *Auxiliary Feedwater System Description and Operation.* Figures 7.3-1, 7.3-12, and Reference Drawings 13, 19 and 20 illustrate the operation of the auxiliary steam generator feedwater pumps system.

A turbine-driven auxiliary feedwater pump, FW-P-2, and two motor-driven auxiliary feedwater pumps, FW-P-3A, 3B, receive suction from the emergency condensate storage tank CN-TK-1, which is encased in concrete for tornado missile protection.

Figure 7.3-1 and Reference Drawing 13 illustrate the start and stop of the motor-driven auxiliary feedwater pumps FW-P-3A & -3B. Reference Drawing 19 and Figure 7.3-12 illustrate the operation of the turbine-driven auxiliary feedwater pump FW-P-2.

Auxiliary feed pump motors can be manually started providing:

1. Control switch is in START either at the control board or at the auxiliary shutdown panel, with the transfer switch in the appropriate position.
2. No motor electrical faults are present, that is, lockout relay is reset. or phase voltage unbalance
3. No undervoltage has occurred on the bus in the previous 25 seconds.

Immediate automatic starting will take place if the following conditions exist:

1. Control switch at the control board or the auxiliary shutdown panel is in AUTO with transfer switch in appropriate position.
2. No electrical faults are present. or phase voltage unbalance
3. The bus has no undervoltage signal present.
4. No safety injection signal is present.
5. Occurrence of any of the following:
   a. All main feed pumps tripped.
   b. Low-low steam generator level on two out of three channels of any steam generator. (This is the same setpoint used for reactor trip.)
   c. Loss of reserve station power.
   d. AMSAC initiated.

In addition to the start demand signals a, b, c and d above, there is also a delayed auto start in the event a safety injection signal is initiated. This start is delayed 20 seconds to maintain an acceptable voltage profile from the offsite source. In the event of an undervoltage signal

No changes for this page. Page provided for reference only.

Table 7.3-2

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

Functional Unit	Channels to Trip	Minimum Channels Operable
1. Safety Injection		
a. Manual Initiation	1	2
b. Automatic Actuation	1	2
c. Containment Pressure—High	2	2
d. Pressurizer Pressure—Low-Low	2	2
e. Differential Pressure Between Steam Lines—High	2/steam line twice and 1/3 steam lines	2/steam line
f. Steam Flow in Two Steam Lines—High	1/steam line any 2 steam lines	1/steam line
Coincident with either		
T_{avg}—Low-Low	1 T_{avg} any 2 loops	1 T_{avg} any 2 loops
or, coincident with		
Steam Line Pressure—Low	1 pressure any 2 lines	1 pressure any 2 lines
2. Containment Spray		
a. Manual	1 set	2 sets
b. Automatic Actuation Logic	1	2
c. Containment Pressure—High-High	2	3
d. Refueling Water Storage Tank (RWST) Level—Low Coincident with Containment Pressure High-High	2	2
3. Containment Isolation		
a. Phase "A" Isolation		
1) Manual	1	2
2) From Safety Injection Automatic Actuation Logic	1	2
c. Phase "B" Isolation		
1) Manual	1 set	2
2) Automatic Actuation Logic	1	2
3) Containment Pressure—High-High	2	3

No changes for this page. Page provided for reference only.

Table 7.3-2 (continued)

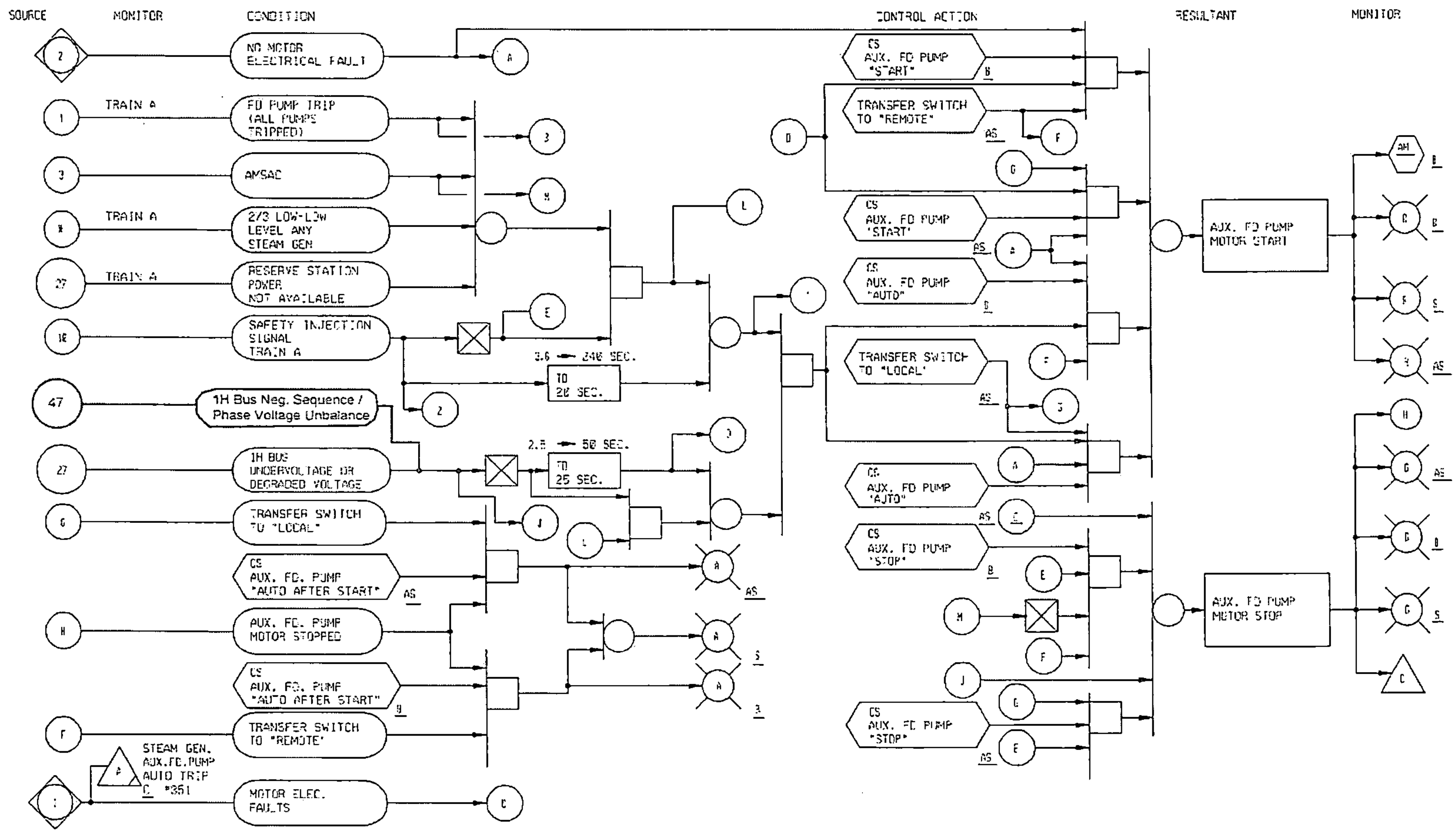
ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

Functional Unit	Channels to Trip	Minimum Channels Operable
4. Steam Line Isolation		
a. Manual	1/steam line	2/steam line
b. Automatic Actuation Logic	1	2
c. Containment Pressure—Intermediate High-High	2	2
d. Steam Flow in Two Steam Lines—High	1/steam line any 2 steam lines	1/steam line
Coincident with either		
T_{avg}—Low-Low	1 T_{avg} any 2 loops	1 T_{avg} any 2 loops
or, coincident with		
Steam Line Pressure—Low	1 pressure any 2 lines	1 pressure any 2 lines
5. Turbine Trip & Feedwater Isolation		
a. Steam Generator Water Level—High-High	2/loop	2/loop
b. Automatic Actuation Logic and Actuation Relays	1	2
c. Safety Injection (SI)	See #1 above (All SI initiating functions and requirements)	
6. Auxiliary Feedwater Pump Start		
a. Manual Initiation	1	2
b. Automatic Actuation Logic	1	2
c. Steam Generator Water Level—Low-Low	2/steam generator	2/steam generator
d. Safety Injection (SI)	See #1 above (All SI initiating functions and requirements)	
e. Station Blackout	1/bus on 2 busses	1/bus on 2 busses
f. Main Feed Pump Trip	1/pump	1/pump
7. Switchover to Containment Sump		
a. Automatic Actuation Logic and Actuation Relays	1	2
b. Refueling Water Storage Tank (RWST) Level—Low-Low	2	3

Table 7.3-2 (continued)
ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

Functional Unit	Channels to Trip	Minimum Channels Operable
8. Engineered Safety Feature Actuation System Interlocks		
a. Pressurizer Pressure, P-11	2	2
b. Low-Low T_{avg}, P-12	2	2
c. Reactor Trip, P-4	1	2
9. Loss of Power		
a. 4.16 Kv Emergency Bus Undervoltage (Loss of Voltage)	2/bus	2/bus
b. 4.16 Kv Emergency Bus Undervoltage (Grid Degraded Voltage)	2/bus	2/bus
c. 4.16 Kv Emergency Bus Negative Sequence Voltage (Phase Voltage Unbalance / Open Phase Condition)	2/bus	2/bus

Figure 7.3-1
LOGIC DIAGRAM MOTOR DRIVEN STEAM GENERATOR AUXILIARY FEED PUMPS

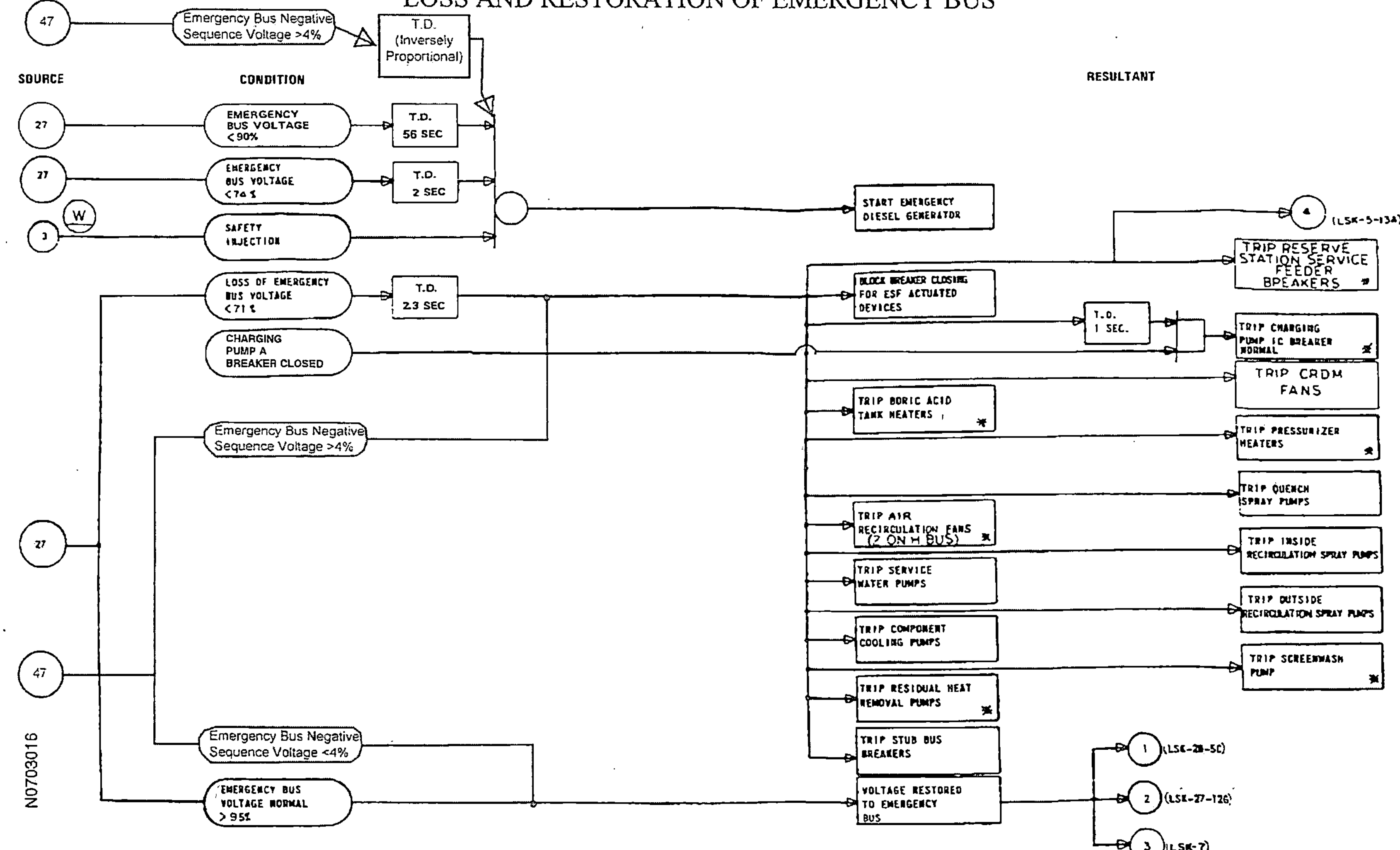


NOTES:

1. LOGIC FOR FW-P-3A SHOWN. LOGIC FOR FW-P-3B SIMILAR.
2. LOCATION SYMBOL "AS" REFERS TO AUXILIARY SHUTDOWN PANEL.
3. OTHER POSITION OF TRANSFER SWITCH IS "AS".
4. TRANSFER SWITCH CHANGED FROM "LOCAL" TO "REMOTE" CONTROL REMAINS LOCAL UNTIL LOCKOUT RELAY AT SWGR. RESET.
5. LIGHTS AT "AS" ONLY ILLUMINATE WITH TRANSFER SWITCH IN "LOCAL".

N0703001

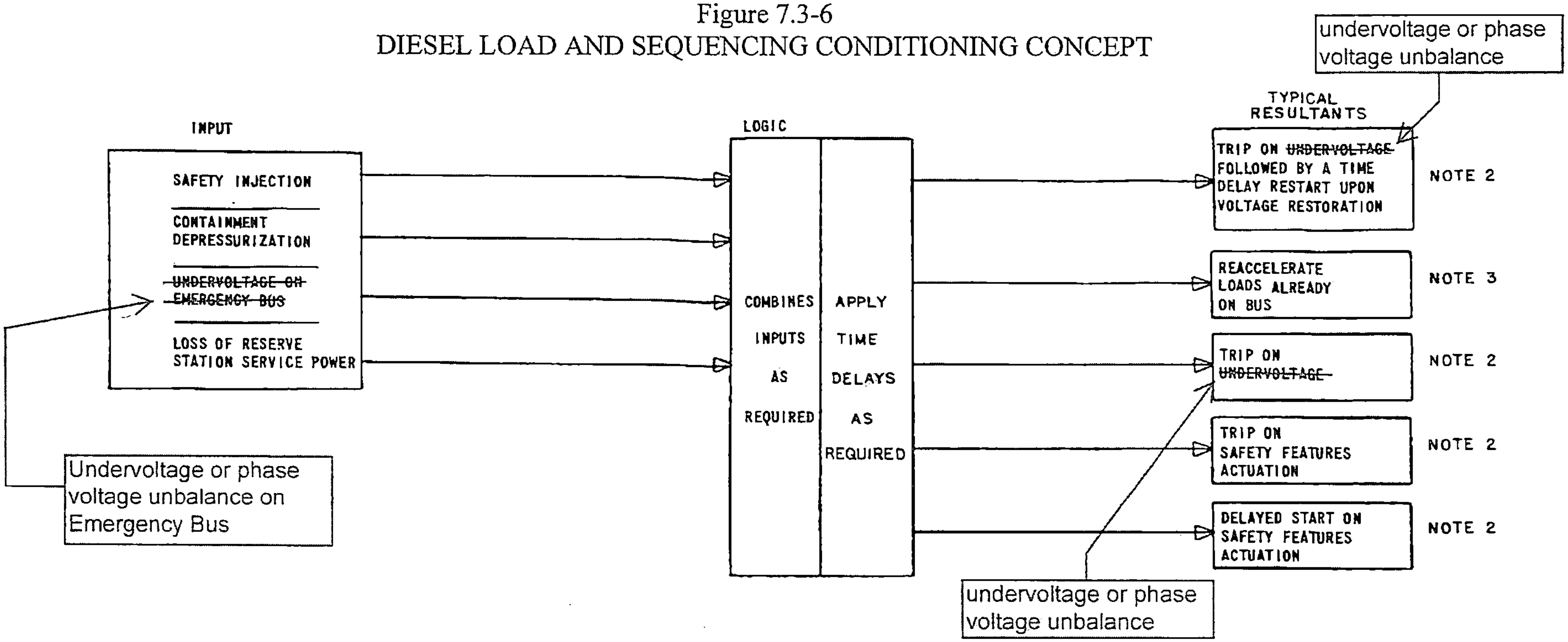
Figure 7.3-5
LOSS AND RESTORATION OF EMERGENCY BUS



* NO AUTO RESTART EXCEPT IN THE CASE OF CONTAINMENT AIR RECIRCULATION FANS— ONLY ONE OF THE TWO FANS ON THE H BUS HAS AUTO RESTART CAPABILITIES

The information contained in the electronic version of the SAR may be different from the information found in the hardcopy version of the SAR. Such differences are intentional and are the result of approved changes to the SAR that have not yet been submitted to the NRC.

Figure 7.3-6
DIESEL LOAD AND SEQUENCING CONDITIONING CONCEPT



NOTES: 1. THIS DRAWING IS A GENERAL BLOCK DIAGRAM. LOGIC IS SHOWN ON SUBSEQUENT DIAGRAMS, IN 7.3.

2. THE RESULTANTS SHOWN REFER TO TYPICAL OPERATIONS OF THE BREAKERS WHICH CONNECT SIGNIFICANT LOADS TO THE EMERGENCY BUS.

3. THIS RESULTANT REFERS TO EMERGENCY BUS LOADS WHICH WILL NOT REQUIRE ANY DELIBERATE BREAKER OPERATIONS FOR ANY COMBINATION OF THE INPUTS SHOWN.

DIESEL LOAD AND SEQUENCE CONDITIONING CONCEPT

N0703017

The 4160V emergency switchgear is arranged in two separate systems designated H and J. The H bus is associated with train A, while the J bus is associated with train B. The buses are physically as well as electrically, separated from each other in different missile-protected areas on the bottom floor of the service building as shown in Reference Drawing 18. The 4160V H and J buses are arranged as shown in Reference Drawing 4. The 4160V buses are rated 1200A serving emergency loads through breakers equipped to protect the loads from overcurrent. The 480V emergency switchgear is also separated and located in missile-protected areas.

The 480V emergency switchgear buses H and J are arranged as shown in Reference Drawing 5. These buses are rated at 2000A with breakers equipped with overcurrent protection for the loads. The 480V motor control centers are shown in Reference Drawings 6 through 11 and 19.

The 480V emergency buses are equipped with normally open back feed breakers and an electrical connection which can be powered by a portable generator during a Beyond Design Basis Event.

The loads on the H and J buses on either the 4160V or the 480V level are typically redundant and are sized based on their required functions or the required functions of their associated components (e.g. a motor on a safety-related pump). The safety-related buses and their loads are shown in Reference Drawings 1 through 11 and 19.

There are other interconnections between buses, buses and loads, and buses and sources on the emergency 4160V system. The interconnection between bus and supply will be described for the H bus only since the J bus is identical, with the exception of the reserve station service transformer and transfer bus used and as noted in the following paragraph.

or open phase condition

undervoltage, overcurrent, or open phase condition.

The H bus is connected to the reserve station service transformer C, its preferred supply, through a feeder breaker from the transformer to transfer bus F and two breakers in series between the transfer bus and the emergency bus. The feeder breaker from the transformer trips on overcurrent; transfer bus undervoltage; both 34.5 kV breakers (powering the transformer) open; or reserve station service transformer pilot wire, differential, or overcurrent. The breaker from the transfer bus trips due to overcurrent; undervoltage on either of the transfer or emergency buses; a trip of the feeder breaker from the transformer to the transfer bus; or transformer pilot wire, differential, or overcurrent. The feeder breaker in the emergency bus will trip due to an emergency bus ~~undervoltage or overcurrent~~. The emergency diesel generator starts when a safety injection signal is received, at approximately 74% voltage on the bus for 2 seconds, ~~or~~ a 90% degraded voltage level exists for 56 seconds. Following the safety injection start signal, the emergency diesel generator will load if a 90% degraded voltage level exists for 7.5 seconds. The emergency diesel generator breaker closes on the isolated bus at 95% generator voltage if certain conditions are met. The load breakers automatically trip on overcurrent or electrical fault and lock out, which prevents the breaker from being reclosed manually or automatically. Most of the 4160V load breakers also trip on undervoltage with time controlled reclosing when voltage is

, or when an open phase condition is detected. [ADD TEXT FROM INSERT A HERE]

or phase voltage unbalance

Insert A

An open phase condition causes a voltage unbalance on the system which is detected via emergency bus negative sequence voltage relays. The negative sequence voltage relays include an inverse time characteristic which introduces a trip time delay based on the magnitude of the negative sequence voltage above the nominal setting of 4%. A time dial setting is used which results in a typical trip time delay of less than 6 seconds for any open phase condition sensed at an emergency bus.

restored on the bus. When a load breaker control switch is in the automatic position, the breaker will automatically close, as dictated by system requirements. All loads served by the stub bus, connected to the emergency bus, are shed due to undervoltage and may be manually reconnected. The stub bus tie breaker is tripped and locked out when a containment depressurization actuation signal exists. The 480V emergency buses and motor control centers have no means of interconnections. Some 480V feeder breakers, in the motor control centers, automatically shed their loads on loss of offsite power to reduce emergency diesel generator loading.

On Unit 1, normal to emergency bus ties have been installed and, with the Unit 1 main generator breaker, provides two independent offsite power sources to each emergency bus. These bus ties exist between emergency bus 1H and the normal 4160V bus 1B and between the normal 4160V bus 2B and emergency bus 1J. These bus ties have a normally open breaker at each bus. In conjunction with this modification, the administrative tie between emergency buses 1H and 1J was removed.

On Unit 2, normal to emergency bus ties have been installed which provide an independent offsite power source to each emergency bus. These bus ties exist between emergency bus 2H and the normal 4160V bus 2C and between the normal 4160V bus 1A and emergency bus 2J. These bus ties have a normally open breaker at each bus.

a degraded voltage, loss of voltage, or open phase condition,

On ~~either degraded voltage or loss of voltage~~, an emergency bus will automatically transfer from its normally connected reserve station service transformer to the diesel generator. Manual transfer capability to the normal station service bus is also provided.

On Unit 2, the feeder breakers from the normal source (main generator) to the normal buses trip on overcurrent; undervoltage on the normal bus; turbine stop valve differential; generator differential; generator negative phase sequence; generator loss of field; generator ground; generator backup; generator overexcitation; generator leads differential; transmission line (A, B, or C) differential overcurrent; main transformer sudden pressure; turbine intercept and reheat valve differential; or generator power circuit breakers open. Tripping these breakers will, in turn, provide a permissive to close the breaker from the preferred power source (RSSTs) if there is no overcurrent on the normal bus and no undervoltage on the preferred source. The normal source feeder breakers that have tripped are locked open.

On Unit 1, the various main generator faults discussed above cause the tripping of the main generator breaker rather than the main feeder breakers from the normal source to the normal buses. The conditions of overcurrent, undervoltage on the normal bus, transmission line differential overcurrent, or sudden pressure, still trip the main feeder breakers. The main generator breaker trips associated with main generator faults or reactor trips allow power to be provided to the normal buses from the 500-kV switchyard instead of transferring to the preferred source as discussed on page 8.3-3.

To alleviate potential low-voltage profile conditions of the reserve station service system during combined unit operation using only the reserve station service system transformers, a load-shedding scheme to certain non-safety-related secondary plant electrically driven equipment has been incorporated. When used, this scheme sends tripping signals to specific pieces of equipment based on the position of a "unit start-up" switch and the status of certain plant equipment. The tripping signal will trip specified running equipment and will defeat the auto-start capability of nonrunning equipment.

For the system to function, the operator places a two-position control switch in either the Unit 1 or Unit 2 start-up position. The particular equipment to be tripped by the switch positions will depend on the operating status of the main feedwater pumps, while other equipment will always receive a trip signal when load shedding is initiated.

The load-shedding scheme will initiate whenever the Unit 1 and Unit 2 normal (A, B, or C) bus is being fed from its associated reserve station service transformer, unless the operator has specifically defeated load shedding. To ensure the requirements of GDC-17 are met, load shedding should be enabled when (1) one unit is on-line and the other is in startup, (2) both units are on-line, or (3) both units are in startup. It may be necessary to defeat the load shed circuit for short periods to support maintenance activities. This will be procedurally controlled.

The equipment that is tripped any time load shedding is initiated is given in Table 8.3-1. The other equipment powered by a particular reserve station service transformer is selectively tripped depending on the unit start-up switch position and the status of the feedwater pump in that unit. This results in six possible combinations of equipment to be tripped in addition to the equipment that is normally tripped for load shedding. The combinations are given in Tables 8.3-2, 8.3-3, and 8.3-4.

or open phase condition sensed

An undervoltage sensed on the preferred source feed trips the preferred source supply breakers, which, in turn, trip and lock open the preferred source feeder breakers to the emergency buses. An undervoltage ~~caused~~ on the emergency buses trips the preferred feeder breaker to the emergency buses and the associated emergency bus preferred supply breakers. These two breakers, which tie the transfer buses with the emergency buses, are in series so that a stuck breaker does not affect the clearing of the emergency buses from outside power sources before the connection of the diesel generators to the emergency buses.

Safety-related loads that may be transferred manually from one emergency bus to the other are charging pump C (CH-P-1C) and containment recirculation cooler fan C (HV-F-1C). Channel 1 of the excore neutron flux monitor system (AMP-NM-1) can be powered from an emergency bus on the other unit.

The charging pump C is normally operated as either:

1. Running, in case pump A or B (CH-P-1A or CH-P-1B, respectively) is out for maintenance or otherwise not preferred to be in operation.

2. Available (not running) when either pump A or B is running.

Even though charging pump C may be powered from either the H or J emergency buses through breakers 15H7 or 15J7, respectively, interconnection of the buses cannot occur. These breakers are electrically interlocked to prevent inadvertant, simultaneous closing of both breakers.

To prevent overloading of the diesel generators, interlocks prevent automatic operation of two charging pumps on an emergency bus that has experienced an undervoltage. or phase voltage unbalance

During a safety injection signal with no loss of power, the A and B charging pumps, if available, will automatically start, but the diesel generators, even though started with the safety injection signal, will not be connected to their respective buses so they cannot be overloaded. Normally only one charging pump (A or B) is required to run, with the other remaining pump (A or B) in the automatic mode. The C pump is normally a "swing" pump - available to be manually started when the A or B pump is unavailable (or it is not desired to operate them). If the C pump is to be considered an operable pump, it will be running, since the C pump gets no automatic starts.

The elementary diagram numbers showing the breaker interlocks mentioned above are 11715-ESK-5AL, 5AM, 5AN, and 5AP and are contained in Reference 1.

The indicators for each of the three charging pumps are as follows:

1. Green, red, and amber breaker position indication lights, located locally at switchgear, on the main control board and the auxiliary shutdown panel.
2. Ammeters, located on the main control board.
3. Annunciation on the main control board including "86 lockout trip" for all four breakers associated with the three pumps.
4. Charging pump flow on main board and auxiliary shutdown panel.
5. Computer inputs include "breaker closed" for all four breakers associated with the three pumps.

The requirements of the single-failure criterion have been satisfied by providing three full-sized pumps and proper control design so that there will always be one pump available, even with a pump out for maintenance.

Three containment recirculation cooler fans are used for containment ventilation. The A and B fans are powered from the H and J emergency busses, respectively. The C fan can be powered from either the H or J emergency bus through breaker positions 14H7 or 14J7, respectively. Even though containment recirculation cooler fan C may be powered from either H or J emergency busses, the interconnection of the busses can not occur. There is only one breaker, and it has to be physically taken out of one cubicle and inserted into the other position.

, undervoltage, or phase voltage unbalance.

All three containment recirculation fans are tripped by a containment depressurization actuation (CDA) signal ~~or undervoltage~~. Fans A and B are available to be manually restarted when the CDA signal is reset and after a 30 seconds. delay on restoration of voltage. Fan C is

No changes for this page. Page provided for reference only.

available to be manually restarted when the CDA signal is reset and on restoration of voltage. The elementary diagrams showing the breaker controls are 11715-ESK-6B, -6C, -6D, and -6E and are contained in Reference 1.

The indicators for each of the three containment recirculation cooler fans are as follows:

1. Green, red, and amber breaker position indicating lights, located on the ventilation panel in the main control room.
2. Annunciation on the main control board of breaker trip for each of the fan breakers.
3. Computer inputs for each fan breaker.

The requirements of single-failure criterion have been satisfied by providing proper control design to ensure that interconnection of the emergency busses will not occur.

Channel 1 of the Excore Neutron Flux Monitor System can be operated using either Unit 1 or Unit 2 emergency power. The option to use power from the opposite unit was provided to ensure that indication for this parameter would be available in the Fuel Building following a fire in the Control Room, Emergency Switchgear Room, Cable Tunnel, or Cable Vault.

For Unit 1, the transfer to Unit 2 power is made in the Unit 2 Emergency Switchgear Room. A breaker in the Unit 1 Emergency Switchgear Room protects the Unit 1 Emergency Power System from faults caused by a fire in the Unit 2 Emergency Switchgear Room. The Unit 2 design is similar.

The transfer switches cannot be positioned to connect Unit 1 and Unit 2 Emergency Power Systems.

The identification of safety-related equipment enables plant personnel to recognize safety-related components. The emergency buses are color coded with the H bus designated as orange and the J bus designated as purple, and all cables associated with these buses that have safety-related functions are also color coded. The equipment is related to its associated bus by the alphanumeric equipment mark number; that is, the H bus feeds A, C, E, etc., designated equipment, and the J bus feeds B, D, F, etc., designated equipment.

The controls for the 4160V and 480V emergency switchgear breakers are powered from the battery (125V dc) distribution switchboards, as described in Section 8.3.2. The supplies are separate to ensure the redundancy of the control power for proper actuation of the breakers and are arranged so that the distribution board I is associated with bus H and board III with bus J.

The emergency switchgear is energized during normal operation, but not all equipment is continuously running. Because this situation exists, it becomes necessary to ensure that the equipment will work when it is needed. Therefore, tests of the entire system or components are conducted at specified intervals in accordance with Technical Specification requirements. The entire standby system is tested after installation to verify the starting speed and load ability. After acceptance, the standby power systems are operated on a routine test schedule. Automatic starting of the diesel generators, an essential part of the safety-related systems, is tested in accordance with Technical Specifications.

Load Shedding and/or auto-start blocking of large 4160V motors is provided when the normal or "G" buses are being fed from the reserve station service transformers, to alleviate potential low-voltage profile conditions on the emergency buses during unit emergency (SI or CDA) conditions. This scheme is in addition to and separate from the load shedding previously described in this section.

- For the condition of bus 2A being fed from RSST "A" during a Unit 1 SI or CDA, loads 2-SD-P-1A and 2-SD-P-2A will be shed.
- For the conditions of bus 2B being fed from RSST "B" during a Unit 1 SI or CDA, loads 2-SD-P-1B, 2-FW-P-1B1, 2-FW-P-1B2 and 2-CN-P-1B will be shed.
- All circulating water pumps of either unit experiencing an SI or CDA will be tripped when both buses 1G and 2G are being fed from the same source.

Automatic starting of the Condensate, Bearing Cooling, Component Cooling and Steam Generator Feed Pumps will be blocked during an SI or CDA when bus alignments are such that starting one or more of the pumps will degrade the voltage on the emergency bus.

The voltage correction mechanism on the Load Tap Changers for Reserve Station Service Transformers A, B, and C receives a signal to provide instantaneous voltage correction upon the occurrence of an SI signal on either unit. The signal will last for the duration of the event.

The equipment capacities are specified to meet the plant requirements and are shown in Reference Drawings 2 through 11 and 19.

, or phase voltage unbalance causes >4% negative sequence voltage on the bus (relay trip time is < 10 sec and inversely proportional to the magnitude of the negative sequence voltage).

Emergency Diesel Generators

The emergency diesel generator, being a vital part of the emergency onsite power system, is discussed in detail below.

There are two 100%-capacity diesel generators for each unit. The diesel generators will automatically start when a safety injection signal is received, a 90% degraded voltage level for 56 seconds is sensed on the bus, ~~or~~ approximately 74% voltage for 2 seconds exists on the bus. Following the safety injection start signal, the emergency diesel generator will load if a 90% degraded voltage level exists for 7.5 seconds. When approximately 74% voltage is sensed for 2 seconds, or if the degraded voltage condition exists, the emergency bus is isolated and load shedding begins. The generator output breaker automatically closes onto the bus when the generator output voltage reaches 95% of nominal, either of the normal offsite power supply breakers are open, limited residual voltage remains on the bus, and the generator differential auxiliary relay is reset. An additional permissive exists for the emergency diesel generators output breakers requiring either of the bus-tie breakers to be open. Residual voltage on the Emergency undervoltage, degraded voltage, and phase voltage unbalance

Bus is sensed by a relay that allows breaker closure only after the residual voltage has dissipated to approximately 1050V. The ~~undervoltage and degraded voltage~~ relaying schemes that initiate load-shedding are defeated when the diesel generator output breaker closes onto an isolated bus.

This is necessary to prevent voltage drops encountered during the diesel-loading sequence from causing load shedding to recur.

The following conditions will render the diesel generators incapable of responding to an emergency start signal discussed above:

1. Shutdown relay not reset.
2. Diesel generator (87) differential relay not reset.
3. Battery failure (100% loss of dc power).
4. Clogged or air-bound fuel oil lines.
5. Injection racks not open.
6. Air distributor valves sticking or low air pressure (less than 175 psig).
7. Air-start valves fail.
8. Improper governor setting or governor failure.
9. Improper set or faulty overspeed relay.
10. Engine firing on lube oil.
11. Control Room selector switch in MAN LOCAL.

These conditions are annunciated either directly based on the situation or indirectly via a start failure alarm in the diesel generator room and via an emergency diesel generator (EDG) Trouble Alarm in the main control room. The diesel will also fail to start if the air start manual isolation valves are closed. These valves are locked in the open position and are checked periodically to ensure that they will not prevent the diesel generator from starting.

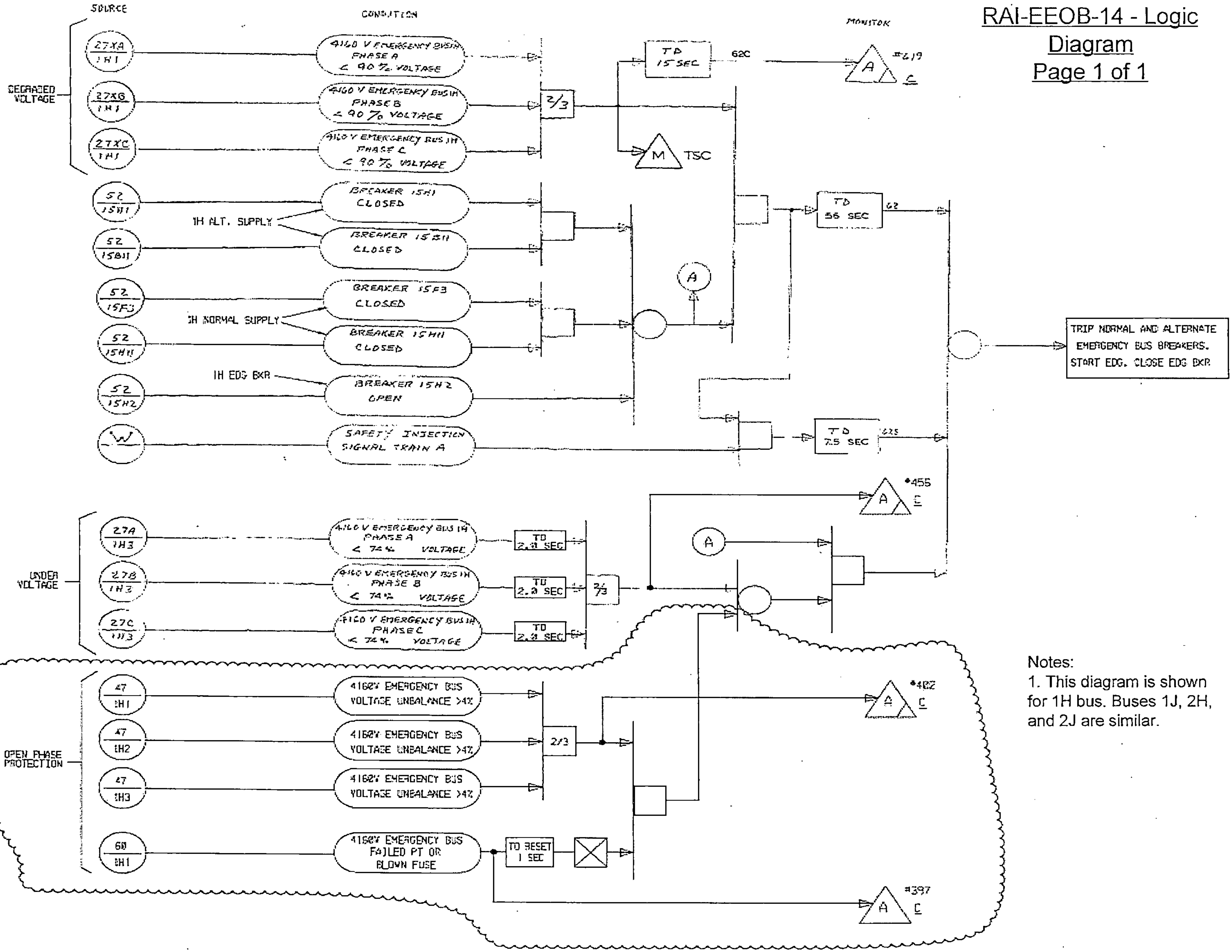
A listing of all equipment on the bus, including loading and unloading by manual or automatic action, time of each event, size of load, identification of redundant equipment, and length of time each load is required is shown in Table 8.3-6 for the H bus and Table 8.3-7 for the J bus. The schedules were set up in order to ensure that the emergency diesel-generator loading satisfies Position 2 of Safety Guide 9. The sequence of events used in the development of the schedules is as follows, where $T_0 = 0$ seconds: (1) safety injection signal occurs at T_0 - 50 seconds, (2) loss of preferred power source is sensed by undervoltage relays at T_0 seconds, and (3) the CDA signal occurs at T_0 + 55 seconds. Tables 8.3-6 and 8.3-7 show two Unit 1 scenarios as examples. While these scenarios do not bound worst-case EDG loading, they show the sequencing of loads for these events. Engineering controls and incorporates load additions into worst-case voltage profile and load calculations to ensure EDG ratings are not exceeded.

Attachment 8

Logic Diagram for Negative Sequence Voltage Relay Scheme

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

RAI-EEOB-14 - Logic Diagram
Page 1 of 1

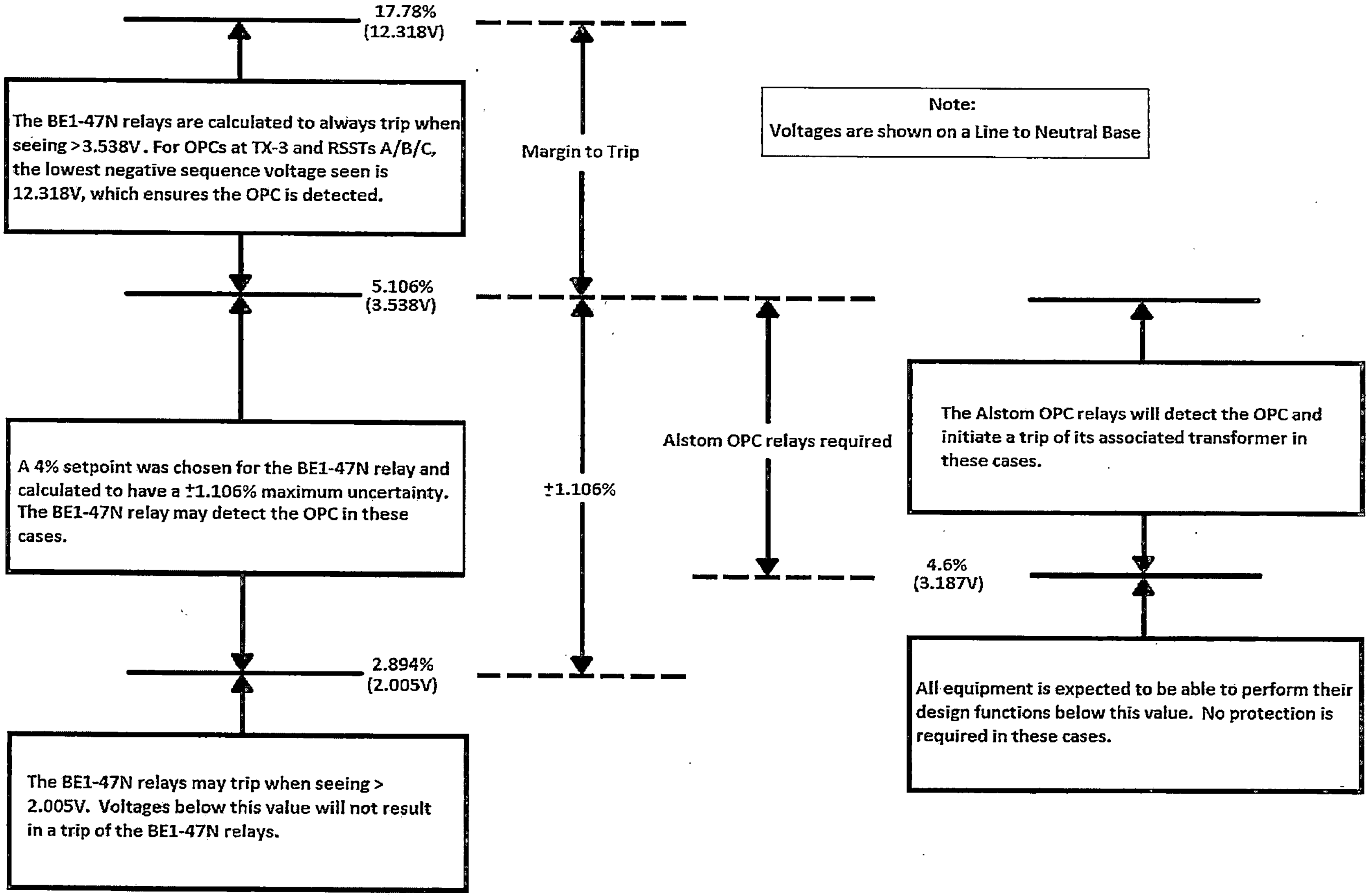


Notes:
1. This diagram is shown for 1H bus. Buses 1J, 2H, and 2J are similar.

Attachment 9

Visual Representation for the Response to *RAI-EEOB-15*

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


17.78%
(12.318V)
The BE1-47N relays are calculated to always trip when seeing >3.538V. For OPCs at TX-3 and RSSTs A/B/C, the lowest negative sequence voltage seen is 12.318V, which ensures the OPC is detected.
Margin to Trip
Note:
Voltages are shown on a Line to Neutral Base
5.106%
(3.538V)
A 4% setpoint was chosen for the BE1-47N relay and calculated to have a ±1.106% maximum uncertainty. The BE1-47N relay may detect the OPC in these cases.
±1.106%
Alstom OPC relays required
The Alstom OPC relays will detect the OPC and initiate a trip of its associated transformer in these cases.
4.6%
(3.187V)
2.894%
(2.005V)
All equipment is expected to be able to perform their design functions below this value. No protection is required in these cases.
The BE1-47N relays may trip when seeing > 2.005V. Voltages below this value will not result in a trip of the BE1-47N relays.