Virginia Electric and Power Company
d/b/a Dominion Energy Virginia – Electric Transmission
(DEV-ET)

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TABLE OF CONTENTS

1.0 PURPOSE

1.1 **Purpose of NERC Reliability Standard FAC-001:** To avoid adverse impacts on the reliability of the Bulk Electric System (BES), Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information.

1.2 **Purpose of this Document:** This Virginia Electric and Power Company d/b/a Dominion Energy Virginia-Electric Transmission (DEV-ET) NERC Compliance Procedure (NCP) establishes a primary resource for procedures (detailed within the document or referenced) that demonstrate DEV-ET's compliance with NERC Reliability Standard FAC-001, Requirements R1 and R3.

2.0 REFERENCES

2.1 North American Electric Reliability Corporation (NERC) website at www.nerc.com

2.1.1 NERC Glossary of Terms

2.1.2 NERC Reliability Standards

2.2 PJM Interconnection L.L.C (PJM) website at www.PJM.com

2.2.1 PJM Manual 14A: New Services Request Process

2.2.2 PJM Manual 14C: Generation and Transmission Interconnection Facility Construction

2.2.3 PJM Manual 14D: Generator Operational Requirements

2.2.4 PJM Manual 14G: Generation Interconnection Requests

2.2.5 PJM Manual 01: Control Center and Data Exchange Requirements

2.2.6 PJM Manual 03: Transmission Operations

3.0 APPLICABILITY

3.1 Applies to DEV-ET as a registered Transmission Owner (TO) with NERC.

3.2 NERC Reliability Standard FAC-001 Requirements applicable to DEV-ET as a registered TO: R1 and R3.

3.3 NERC Reliability Standard FAC-001 Requirements not applicable to DEV-ET as a registered TO: R2 and R4.

4.0 PROCEDURE

R1

Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for:

1.1 generation Facilities;

1.2 transmission Facilities; and

1.3 end-user Facilities.

Compliance R1

DEV-ET's Facility Interconnection Requirements (FIR) document is publicly available on the company's web site (www.dominionenergy.com) and is provided to PJM (www.pjm.com) to provide guidance to Interconnection Customers seeking to connect to its Transmission System. It also serves as evidence that DEV-ET documents Facility interconnection requirements, updates them as needed, and makes them available upon request, as required by NERC Reliability Standard FAC-001.

DEV-ET is also referred to in this document as "Company".

1.1 Generation Facilities

This document complies with NERC Reliability Standard FAC-001 Requirement R1.1 by addressing interconnection requirements for generation Facilities for each sub-requirement of NERC Reliability Standard FAC-001 Requirement R3.

1.2 Transmission Facilities

This document complies with NERC Reliability Standard FAC-001 Requirement R1.2 by addressing interconnection requirements for transmission Facilities for each sub-requirement of NERC Reliability Standard FAC-001 Requirement R3.

1.3 End-User Facilities

This document complies with NERC Reliability Standard FAC-001 Requirement R1.3 by addressing interconnection requirements for end-user Facilities for each sub-requirement of NERC Reliability Standard FAC-001 Requirement R3.

The provisions of this document apply to Interconnection Customers seeking to connect to DEV-ET's Transmission System, except as may be otherwise provided for in applicable tariffs or agreements, or as may be otherwise agreed to by DEV-ET and the Interconnection Customer.

R3

Each Transmission Owner shall address the following items in its Facility interconnection requirements:

3.1 Procedures for coordinated studies for new interconnections or existing interconnections seeking to make a qualified change as defined by the Planning Coordinator and their impacts on affected systems.

3.2 Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections or existing interconnections seeking to make a qualified change.

3.3 Procedures for confirming with those responsible for the reliability of affected systems that new Facilities or existing Facilities seeking to make a qualified change are within a Balancing Authority Area.

Compliance R3

DEV-ET individually addresses the interconnection requirements of generation, transmission, and electricity end-user Facilities in this document. These Facility interconnection requirements are to be adhered to by any requesting Interconnection Customer who wishes to establish a connection to DEV-ET's transmission Facilities. DEV-ET adheres to these same requirements as it constructs additions to its Transmission System. These requirements should be evaluated as a whole when determining the actions necessary to develop a complete interconnection request.

Transmission connections covered by this document include all generation resources, ties with transmission Facilities owned by others, and Interconnection Customer substations at voltages of 69 kV or greater. It is not practical to include the requirements applicable to every possible transmission connection scenario since each connection is specific to the party requesting the connection and the Transmission System at the point of customer connection. There are several factors to be considered when connecting DEV-ET's Transmission System to (1) another transmission system, (2) a new or additional generation, and (3) a new or additional customer load. The evaluation of these factors requires a power system analysis of the transmission network as described in Attachment 1 of this document.

The standards in this document apply to new Facilities and to modification of existing Facilities. The standards in effect at the time a Facility was constructed or modified are to continue to apply to such Facility until it is subsequently modified, or until DEV-ET or PJM determine the Facility must be upgraded to the current standard to avoid unacceptable risk to the reliability or operation of the Transmission System, or to the safety of workers or the public.

Typical connections are provided in Attachment 1- Dominion Energy Virginia- Electric Transmission Planning Criteria of this document.

This section identifies the requirements and sub-requirements of NERC Reliability Standard FAC-001 R3, along with additional information per the standard's associated Supplemental Guidelines. Unless otherwise noted, details under each topic in this section apply globally to generation Facilities, transmission Facilities, and end-user Facilities. For topics warranting additional, specific requirements regarding generation Facilities, transmission Facilities, and/or end-user Facilities, an associated sub header is clearly provided for the reader.

R3.1

Procedures for coordinated studies for new interconnections or existing interconnections seeking to make a qualified change as defined by the Planning Coordinator and their impacts on affected systems.

Compliance R3.1

The following is DEV-ET's procedures for coordinated studies of new or existing interconnections seeking to make a qualified change as defined by the Planning Coordinator (PC) and their impacts on affected systems.

Utility Interconnections

DEV-ET's Planning group performs planning studies to ensure delivery of bulk power to a continuously changing customer demand under a wide variety of operating conditions.

Should DEV-ET receive an interconnection request that may impact a neighboring interconnected transmission system, DEV-ET initiates contact with that neighboring system for the purpose of coordinating those joint interconnection studies required to assess the impact of the interconnection request on the transmission systems of all affected parties.

Studies are performed in coordination with DEV-ET's Regional Transmission Organization (RTO), which is PJM and in accordance with NERC Reliability Standards, which promote and maintain the reliability and security of the interconnected Bulk Power System.

DEV-ET has entered into various Inter-Area Reliability Agreements with neighboring utilities. The major purpose of these agreements is to further augment reliability and security of each member's bulk power supply system through coordination of planning and operation of their generation and bulk power transmission Facilities. The following is a list of groups with which DEV-ET engages in joint transmission interconnection activities:

- Southeastern Electric Reliability Council (SERC) East-RFC (SER) Studies under the Eastern Interconnection Reliability Assessment Group (ERAG) Agreement
- SERC Intra-Regional Near-Term Studies
- SERC Intra-Regional Long-Term Studies
- ERAG – Multi-Regional Modeling Working Group (MMWG)

Each of these groups has various Working Groups, Study Groups, Committees, Task Forces, etc. that deal with various aspects of power system reliability and security issues. Various studies performed by these groups at the interconnection level include power flows, stability, transfer capabilities, voltage collapse scenarios, tie-line re-closing angles, etc. The basic purpose of these studies is to measure the ability of the transmission network to reliably transfer power in bulk amount from one area to another under the most limiting contingency assumptions that are judged to be credible. These studies can be used in identifying any deficiencies and the needed corrective actions, either through short term operating procedures or by future system upgrades.

Transmission interconnections are planned such that the amount of power that can be transferred between and among the utilities, in addition to firm transactions, is adequate to withstand the most severe credible generation and transmission contingency.

Wholesale Delivery Points

DEV-ET provides transmission service to wholesale delivery points throughout its service area under Mutual Operating Agreement(s) (MOA). The criteria for serving wholesale Interconnection Customers are the same as that used to serve DEV-ET's other customers and is predicated on "Good Utility Practice" and sound engineering and economic principles without regard for the ownership of the Facilities.

Regardless of the generation source of supply to wholesale customers in the company's service area, all supplies are delivered over the company's transmission Facilities. Therefore, it is essential that wholesale Interconnection Customer load requirements be included in the company's planning process.

The following criteria apply to all joint planning between DEV-ET's and its wholesale Interconnection Customers:

- Contractual obligations must be observed.
- Studies must be based on sound engineering and economic principles consistent with long range system plans.
- All applicable sections of the DEV-ET Planning Criteria, provided as Attachment 1 are to apply to the connection of any wholesale Interconnection Customer to DEV-ET's Transmission System.
- Joint planning should be conducted periodically with each wholesale Interconnection Customer. This joint plan includes a review of each company's construction program based on annually updated load forecasts for the general area. The procedure is similar to the following:
    - Load forecasts for each year up to ten years will be prepared by the wholesale Interconnection Customer for their area and by DEV-ET for the general area around the Interconnection Customer.
    - Special emphasis should be given to identify high load growth areas.
    - Existing distributed generation output for both conventional and alternative (solar, wind, etc.) sources, indicating the maximum output of each unit/site, and the output of each unit/site that is coincidental to the summer and winter peak day and time for the DEV zone.
    - The Interconnection Customer and DEV-ET each prepares preliminary studies of their respective systems for meeting the future load requirements identified by the forecasts.
    - The Interconnection Customer and DEV-ET exchange study information and, based on joint analysis, prepare a long-range plan.

There will be instances where deviations from the long-range joint planning process are necessary to accommodate third party delivery point requests. In these cases, the DEV-ET's Planning Department and, as needed, entities interconnected with DEV-ET Facilities, expedite review of appropriate Elements of the long-range plan to address such projects.

All delivery point requests are to include a completed "Customer Request Form" as shown in Attachment 2, Customer Request Form.

R3.2

Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections or existing interconnections seeking to make a qualified change.

Compliance R3.2

The Interconnection Customer is to notify DEV-ET of planned additions of new Facilities, or existing interconnections seeking to make a qualified change which have the potential to impact the reliability of the interconnected transmission systems. Interconnection Customers are to provide such notification as soon as it is feasible for them to do so, even if the information is in a preliminary form. Prompt notification is important so that DEV-ET can begin any needed coordination with other entities responsible for the reliability of interconnected transmission systems. Attachment 2, "Customer Request Form", is to be completed for initial requests as well as subsequent changes.

The form is to be submitted with sufficient advance notice to allow DEV-ET to:

- review the proposed addition or modification,
- conduct the necessary studies to assess the impact of the change on DEV-ET's System and/or neighboring Facility owners,
- respond to the requesting Facility owner
- complete any necessary modifications to DEV-ET Facilities including ownership demarcation of equipment and/or Protection System(s) Elements.

Subsequent changes to the approved design basis are interpreted to include, but are not limited to:

- changes to electrical equipment ratings
- changes to primary conductor(s) or connectors
- changes to transformer tap settings
- changes impacting Protection Systems such as:
- significant source impedance changes at the interconnection point
- modifications to Protection System communications equipment
- modifications to Protection System relay settings
- changes to breaker reclosing times
- Interconnection of new generating Facilities, including distribution connected generation

As modifications are determined to impact other parties, such as power generators, end users, and interconnect parties, DEV-ET will make appropriate notifications and pursue mutually agreeable resolutions, as necessary.

R3.3

Procedures for confirming with those responsible for the reliability of affected systems that new Facilities or existing Facilities seeking to make a qualified change are within a Balancing Authority Area.

Compliance R3.3

PJM is the Balancing Authority (BA) for DEV-ET.

PJM Compliance Bulletin CB028 NERC Standard FAC-001 – Facilities within the metered boundaries of a Balancing Authority, specifies that PJM assesses facilities within its Balancing Authority Area metered boundaries. An Interconnection customer with new Facilities or existing Facilities seeking to make a qualified change seeking interconnection to, or upgrade facilities on the PJM system must do so via the PJM New Services Queue. As a result of external entities engaging PJM for interconnection opportunities, DEV-ET receives drafted agreements from PJM to review and provide comments. Finalization of the agreement occurs upon receipt of signature from the customer, DEV-ET, and PJM. PJM approved projects are given an Interconnection Service Agreement (ISA) and/or an Upgrade Construction Service Agreement (UCSA) and sent to FERC for review and approval. When FERC approves the ISA/UCSA, PJM sends a copy of the approved ISA/UCSA to DEV-ET where it is filed. The approved ISA/UCSA may also be accessed via the PJM "Planning" website by selecting "Services Request Status." PJM specifies that the presence of a PJM issued ISA/UCSA is evidence that can be used by each interconnection customer as confirmation that their new Facilities or existing Facilities seeking to make a qualified change are within the PJM Balancing Authority Area's metered boundaries.

4.1 Supplemental Material per NERC Reliability Standard FAC-001 Guidelines and Technical Basis

4.1.1 *Procedures for Requesting a New Facility Interconnection or Material Modification to an Existing Interconnection*

4.1.1.1 To install, modify, or remove DEV-ET Facilities, or to modify the capacity or characteristics required at a Delivery Point, or to discontinue the delivery of electricity to a Delivery Point, Customer is to initiate requests in writing using the Request/Notification for Changes Impacting DEV-ET Facilities form included in this document. Customer is to also submit a Request Form when making changes to Customer's Facilities that are anticipated to (i) lead to a modification to DEV-ET's Facilities or (ii) impact the operation of DEV-ET's Facilities. See Attachment 2, Customer Request Form.

4.1.2 *Data Required to Properly Study the Interconnection*

4.1.2.1 The Request Form is to be submitted by Customer as soon as useful information is available. As additional or updated information becomes available, Customer is to make timely submission of a revised Request Form. For Request Forms submitted with notations of "(E)" or "TBD by [date]" as described below, DEV-ET and Customer is to determine a schedule for the provision of complete and final information. See Attachment 2, Customer Request Form, pages B-3 through B-5.

4.1.3 ***Voltage level and MW and MVAR capacity or demand at point of interconnection***

4.1.3.1 Except as may be otherwise provided for in applicable tariffs or agreements, or as may be otherwise agreed by DEV-ET and the Interconnection Customer, the Interconnection Customer should use the "Customer Request Form," detailed in or exceed DEV-ET's standard values listed below.

Nominal KV (phase to phase)	Basic Impulse Level (BIL)
115	550
138	650
230	900
500	1550

4.1.3.1 Attachment 2, to provide DEV-ET with the necessary information regarding the voltage level and MW and MVAR capacity or demand at point of connection. Since voltage and interconnection points are site-and project-specific, DEV-ET will perform studies and exercise engineering judgment to determine appropriate voltage levels, interconnection points, and system capabilities.

4.1.4 ***Breaker duty and surge protection***

4.1.4.1 Electrical circuit breakers are to be designed to meet or exceed the expected load and short circuit currents on the Interconnection Customer's transmission system. High voltage circuit breakers and other current interrupting devices are to be designed to clear (interrupt) the worst-case short circuit fault calculated for the protection zone as determined using fault analysis engineering programs.

All current carrying equipment and devices are to be designed to carry the maximum loads that are predicted by load flow analysis. Loads exceeding "nameplate" or "normal" design capacities are only acceptable when allowed by manufacturers design documentation or standard industry practices.

Circuit breakers are to be designed and tested according to the latest Institute of Electrical and Electronics Engineers (IEEE) C37 collection of standards.

Shielding, and surge protective devices are to meet the requirements as determined by lightning and switching surge analysis, and the latest IEEE C62 standards.

Basic Impulse Levels (BIL) for electrical equipment and high voltage substation buses are to meet or exceed DEV-ET's standard values listed below.

Nominal KV (phase to phase)	Basic Impulse Level (BIL)
115	550
138	650
230	900
500	1550

The Interconnection Customer must meet the following design requirements described in NERC Reliability Standard FAC-001 and its SERC Guideline:

- Each party is responsible for designing equipment to meet the short circuit capabilities on their Facilities.
- Each party is responsible for the ratings of their own interrupting devices. It is the responsibility of the Interconnection Customer to coordinate their relays and devices with DEV-ET's Transmission System.

- Parties are to provide existing and future fault current levels when requested.

It is the responsibility of the Interconnection Customer to notify DEV-ET of any changes in their Facilities that may cause an increase in fault currents (generator and transmission Interconnection Customers).

4.1.5 ***System Protection and Coordination***

The Interconnection Customer is responsible for providing a properly designed and tested Protection System that will safeguard the general public, protect its equipment against disturbances on DEV-ET's system, and minimize the effects of disturbances from its Facilities on DEV-ET's equipment and Transmission System. Protection Systems installed by the Interconnection Customer are expected to follow the latest IEEE C37 and C57 guides and standards for protective relaying systems and adhere to NERC and PJM standards related to system protection. The Interconnection Customer's Protection System is to coordinate with the interconnected Protection System owned by DEV-ET. NERC Reliability Standards, operating voltage and proximity to a generating unit will be major considerations for establishing the required protection scheme on a transmission line that connects to DEV-ET's transmission grid. For more information on generator interconnection, see Attachment 3, DEV-Generator Interconnection Protection Requirements.

Prior to the development of the Protection System, the Interconnection Customer should complete all appropriate studies, including, but not limited to, grounding studies, short circuit studies, stability studies, and power quality studies. These studies should be completed using Good Utility Practice and the results made available to DEV-ET upon request.

In addition, DEV-ET performs studies on existing Protection Systems which may require changes to the Interconnection Customer's Protection System. In such cases, those customers will be notified and consulted regarding the changes required to ensure the reliable operation of DEV-ET's transmission Facilities.

4.1.5.1 *Protection System Design*

The Interconnection Customer is to design the Protection System to minimize the effects of disturbances from its Facilities affecting DEV-ET interconnected Transmission System or customers. The Protection System is to: be sensitive to detect all faults and abnormal conditions, provide coordination between protection zones, and operate quickly to achieve Transmission System reliability. In some cases, DEV-ET may require the Interconnection Customer to install additional equipment as necessary to address issues such as, but not limited to, relay overreach, transformer penetration, weak source, source impedance ratio (SIR), anti-islanding, and power quality. DEV-ET is to own and maintain transmission Protection System Elements necessary to protect the transmission portion of the interconnection; however, DEV-ET is not responsible for protection of the Interconnection Customer's equipment and other electrical assets.

The Protection System is to protect against or minimize the effects of abnormal conditions including, but not limited to, over/under-voltage, over/under-frequency, harmonics, overload, short circuits, open circuits, phase imbalance, switching surges, lightning surges, and other harmful electrical conditions. Utility grade protective relays and fault clearing systems are to be provided on the interconnected power system. All protective relays are to meet or exceed American National Standards Institute (ANSI)/IEEE Standard C37.90. Mechanical and electrical logic, interlocking mechanisms, and operational data may be required between interconnected Facilities to ensure safe and reliable operation. Examples of mechanical and electrical logic, interlocking mechanisms, and operation data include, but are not limited to, breaker and switch auxiliary contacts, synch-check relays, physical locking devices, solar irradiance, and inverter operating modes or setpoints.

The following defines DEV-ET's protection requirements for protecting transmission Elements connecting to DEV-ET's transmission grid:

Dual Primary Phase and Ground Protection Systems

Protection Systems classified as Dual Primary are required for all transmission Elements connecting to DEV-ET's transmission grid. This scheme will require two independent high-speed, phase and ground fault Protection Systems designated System 1 and System 2. Together these systems provide a redundant set of all normal primary and backup functions.

Breaker Failure Protection

A breaker failure function is required for all interrupting devices of transmission Elements connecting to a DEV-ET transmission bus as defined by the protection scheme. For Generation Interconnections, there are additional requirements as outlined in Attachment 3, DEV Generator Interconnection Protection Requirements, Section 3 Interconnection Protection Requirements.

Protection System Components

The Interconnection Customer's Protection System, including the protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry, must be compatible with DEV-ET's standard design for common equipment and/or common zones of protection. Compatibility includes protection application, redundancy, operating speed, communication type, and communication medium.

The Protection System must be powered by a DC battery for reliability. The battery is to be sized to power continuous loads for a minimum of 8 hours and power all momentary tripping loads without a charger available. The battery sizing calculation is to be in accordance with IEEE 485. A DC under-voltage alarm must be provided for remote monitoring by the Facilities owner, who are to take immediate action to restore power to the protective equipment.

4.1.5.2 *Protection System Misoperations*

The Interconnection Customer is to investigate all Protection System operations and misoperations, affecting the interconnected Facility and will provide DEV-ET with the findings of the investigations upon request. Likewise, DEV-ET will cooperate with the Interconnection Customer and will provide any necessary findings related to Protection System operations and Misoperations directly affecting the interconnected Facility subject to code of conduct restrictions.

4.1.6 ***Metering and Telecommunications***

4.1.6.1 *Metering*

DEV-ET approved revenue metering equipment is to be installed for energy accounting and billing purposes. Except as may be otherwise provided for in applicable tariffs or agreements, or as may be otherwise agreed by DEV-ET and the Interconnection Customer, the Interconnection Customer is to install, own, operate, and maintain all revenue metering equipment as set forth below.

Interconnection Customers that will be a PJM market participant are to install metering that is to be of sufficient quality to meet the applicable requirements as defined in PJM Manuals 14A – New Services Request Process, 14C – Generation and Transmission Interconnection Facility Construction, 14D – Generator Operational Requirements, and 01 – Control Center and Data Exchange Requirements. Additional requirements may be applicable on a case-by-case basis.

Revenue metering equipment includes, but is not limited to, current transformers, voltage transformers, revenue meters, meter sockets, test switches, communication circuits and associated devices. The revenue metering equipment is to be located at the Interconnection Customer’s Facility unless otherwise agreed to by DEV-ET, PJM, and the Interconnection Customer (referred to collectively in this section as the “Parties”). The revenue metering equipment is to meet or exceed all applicable industry standards (e.g., NERC, PJM, ANSI, IEEE, and National Electrical Manufacturers Association (NEMA)). At least (N-1) metering Elements are to be used for the revenue metering, where N is the number of wires in the electrical system associated with the revenue metering. Three metering Elements are to be the standard for revenue metering unless otherwise agreed to by the Parties. The revenue metering installation is to meet all applicable industry standards for phase-to-phase and phase-to-ground electrical clearances.

DEV-ET will provide the Interconnection Customer with manufacturer’s installation information for the current and voltage transformers when these devices will be furnished by DEV-ET and installed by the Interconnection Customer.

Revenue Meters

The revenue meters are to be capable of recording, storing, and transmitting bi-directional megawatt-hour (MWh) data and megavar-hour (MVARh) data. However, if required by the applicable tariffs, or if mutually agreed by the Parties, the revenue meters are to instead record bi-directional kilowatt-hour (kWh) data and kilovar-hour (kVARh) data. In general, this data is to be recorded in hourly intervals unless other interval lengths are required by the applicable tariffs or agreed upon by the Parties.

The revenue meters are to have an accuracy class of 0.2% standards as defined in ANSI C12.20. In addition, the revenue meter should meet ANSI C12.1 and C12.10 standards. Testing of meters in service may be requested by DEV-ET, any regulatory agency having jurisdiction over the interconnection, or any other lawfully constituted authority having jurisdiction over meter accuracy.

Revenue Metering Current Transformers

The revenue meters are to be connected to current transformers (CTs) having a minimum metering accuracy class of 0.15% (as defined in IEEE C57.13) at a minimum burden designation of B-1.8 from 1% of nameplate to rating factor. CTs with standard accuracy and/or lower burden designations may be allowed by DEV-ET in special cases, but the secondary burden on the CTs must not exceed the nameplate burden rating. In addition, the CTs meet the ANSI C12.11 standard. The continuous current on the CTs is not to exceed the primary nameplate rating with the thermal current rating factor (RF) applied. The available fault current must not exceed the mechanical and short time thermal limits of the CTs. The revenue meters are to generally be connected to dedicated metering CT secondary circuits and should not share the same circuits with relays or other devices. In cases where power flow varies significantly (e.g., at wind generation Facilities), the Interconnection Customer may be required to provide extended range CTs or additional metering equipment at their own expense.

Revenue Metering Data Communication

The Interconnection Customer is to, at its own expense, install, operate, test, and maintain any communications equipment required by DEV-ET to remotely retrieve revenue metering data from the Interconnection Customer's Facility on a real-time or periodic basis as specified in the sections below for wholesale generation Facilities, transmission Facilities, and end user Facilities. The communication capability of remote interrogation of the revenue data should be compatible with commonly used billing data systems such as MV-90 and Primestone. The Interconnection Customer is to also be responsible for any high voltage isolation equipment that the local telecommunications company may require at the Interconnection Customer's Facility to protect their communications systems from damaging transient voltages that can occur in electrical substations and generation Facilities.

DEV-ET provides the Interconnection Customer access to bi-directional kWh and kVARh pulses from the DEV-ET revenue meters installed at Interconnection Customer Facilities. The pulses, which are provided upon request, is to be used as the source of the revenue metering data where applicable. Alternatively, kWh and kVARh register accumulator data may be provided by other means, e.g., DNP, MODBUS, or similar protocol, to the Interconnection Customer Facilities, in lieu of, or in addition to, analog kWh and kVARh pulses, if such arrangements are agreed upon by both Parties.

4.1.6.2 *Operational Metering Data from Revenue Meters*

Operational metering data (e.g., MW and MVAR) is generally not available from DEV-ET revenue meters that are provided by DEV-ET at Interconnection Customer Facilities. Except as may be otherwise provided for in applicable tariffs or agreements, or otherwise agreed by DEV-ET and the Interconnection Customer, the Interconnection Customer is to, at its own expense, install, operate, test, and maintain any metering and communications equipment necessary to provide operational metering data required from the Interconnection Customer's Facility by one or more of the Parties.

Revenue meters are to be capable of communicating with data acquisition system (“DAS”) equipment such as Remote Terminal Unit (“RTU”) to provide the following real-time bi-directional power and energy data for operational purposes:

- instantaneous power flows
- per phase and three-phase averaged Root-Mean-Squared (“RMS”) voltages
- per phase and three-phase averaged RMS currents with at least two decimal points

A continuous accumulating record of active and reactive energy flows are to be provided by means of the registers on the meters. The revenue meter(s) are to be capable of providing bi-directional energy data flow in either KYZ pulse signals format, or accumulated counters to RTU. Energy data flow accumulator counters may also include register accumulator data delivered to RTU via DNP, MODBUS, or similar protocol. All Parties are to share the same data register buffers regardless of the types of employed data communication methods. For generation Facilities that interconnect to DEV-ET generator interconnection substations, this revenue meter data is to be shared across serial data links established between the two facilities. Further details regarding the requirements for this data exchange can be found in Attachment 5, Electric Transmission Generator Interconnection Data Communications and Data Exchange Requirements. This data is shared between facilities at generator interconnection substations. Requirements for this data exchange are provided in Attachment 5, Electric Transmission Generator Interconnection Data Communications and Data Exchange Requirements. If the accumulation counter method is used, the owner of the meter is to be responsible for freezing the accumulator buffers and no other Party is to freeze them. The accumulator freezing signals are to be synchronized to Universal Time Coordination (UTC) within 1/2 seconds.

The revenue meters' internal clocks and real-time DAS equipment is to be synchronized with Universal Time Coordination (UTC) with 15 seconds resolution.

4.1.6.3 *Revenue Metering Access, Security, and Testing*

Where DEV-ET provides revenue metering equipment, the Interconnection Customer is to grant DEV-ET employees and authorized agents' access to the equipment at all reasonable hours and for any reasonable purpose. Regardless of meter ownership, the Interconnection Customer is to not permit unauthorized persons to have access to the revenue metering equipment.

The meters, test switches and any other secondary devices that could have an impact on the performance of the revenue metering is to be sealed and the seals are to be broken by the party responsible for the equipment only when tests, adjustments, and/or repairs are required.

The revenue metering is to be tested for accuracy as specified by the applicable interconnection service agreement, PJM requirements or regulatory commission regulations by the owner of the metering equipment.

4.1.6.4 *Wholesale Generation Facilities*

For the interconnection Facilities of Wholesale Generators, except as may be otherwise provided for in applicable tariffs or agreements, or as may be otherwise agreed by DEV-ET and the Interconnection Customer, the revenue metering equipment is to be located at the Interconnection Customer's Facility. The revenue metering is to be compensated for losses to the Point of Interconnection (POI) if the metering equipment is not located at the POI.

The revenue metering CTs and VTs are to be installed on the transmission voltage side of the Interconnection Customer's generator step-up transformer(s) or Facility main step-up transformer and/or station service power transformers.

The specific revenue metering requirements for wholesale generation Facilities fall under one of the following categories:

<u>DEV-ET Revenue Metering Requirements for Generation Facilities Connected 69 kV and Higher</u>

The Interconnection Customer is to install, own, operate, test, and maintain the revenue metering equipment at the Interconnection Customer's expense. A redundant revenue meter and real-time Supervisory Control and Data Acquisition (SCADA) data is also required. The SCADA data consists of analog MW and MVAR at all generation, load, and transmission line terminals; analog kV at all buses 69 kV and greater; circuit breaker open/close status for all breakers; other device status points (for example, automatic reclosing on/off). It is preferred that the redundant meter have a different method of telecommunications than the primary meter. DEV-ET provides revenue metering for station service power supply at a generation Facility if the supply is from the DEV distribution system.

DEV-ET Revenue Metering Requirements for Generation Facilities Connected Below 69 kV

DEV-ET is to install own, operate, test, and maintain the revenue metering at the Interconnection Customer's expense. A redundant revenue meter is also required. It is preferred that the redundant meter have a different method of telecommunications than the primary meter.

DEV-ET Revenue Metering Requirements for Behind-The-Meter Generation Facilities Participating in the PJM or Wholesale Energy Markets

DEV-ET is to own, operate, test, and maintain the revenue metering equipment at the POI, except as otherwise specified by the applicable retail tariff or interconnection service agreement. The physical arrangements of such Facilities are often complex. As such, DEV-ET makes a case-specific review of each installation and determines the revenue metering required. Any additional metering equipment or metering data that one or more of the Parties may require for the generation equipment is the responsibility of the Interconnection Customer.

Specific Revenue Metering Requirements for Existing Non-Utility Generator Facilities That Are Ending Power Purchase Agreements with DEV-ET

For an existing non-utility generator (NUG) that is ending its power purchase agreements with DEV-ET and will sell its power in the PJM energy market, DEV-ET is to continue to own, operate, test, and maintain the existing revenue metering equipment at the Interconnection Customer's expense, except as otherwise specified by the applicable tariff or service agreement. The customer is responsible for all PJM meter data reporting requirements; DEV-ET will not report the generation on behalf of the NUG to PJM. The Interconnection Customer's RTU is to provide DEV-ET access to the operational and revenue metering data specified in Telecommunication Section.

4.1.6.5 *Transmission Owner Facilities*

For the interconnection Facilities of Transmission Owners, except as may be otherwise provided for in applicable tariffs or agreements, or as may be otherwise agreed by DEV-ET and the Interconnection Customer, the Interconnection Customer is to install, own, operate, test, and maintain the revenue metering equipment at its Facility. The revenue metering is to be compensated for losses to the POI if the metering equipment is not located at the POI.

The revenue metering CTs and VTs are to be installed at the point(s) where the Interconnection Customer's Facility connects to the DEV-ET System. The exact location of the revenue metering CTs and VTs are to be as determined by agreement between DEV-ET and the Interconnection Customer.

The Interconnection Customer is to provide primary and redundant revenue meters with SCADA data. It is preferred that the redundant meter have a different method of telecommunications than the primary meter.

4.1.6.6 *End-User Facilities*

Except as may be otherwise provided for in applicable tariffs or agreements, or as may be otherwise agreed by DEV-ET and the Interconnection Customer, the provisions of this section apply to all end user revenue metering whether installed by DEV-ET or the interconnected end user.

For the interconnected Facilities of end users, the revenue metering is to be installed on either the primary side or the secondary side of the Interconnection Customer's step-down transformer in accordance with the applicable interconnection agreements. DEV-ET utilizes its best engineering judgment to determine the appropriate location for the revenue metering equipment if the interconnection agreement provides DEV-ET the option to choose either the primary side or the secondary side.

If the revenue metering is installed on the primary side of the Interconnection Customer's step-down transformer, the DEV-ET's CTs and VTs are to be located on the high side of the Interconnection Customer's step-down transformer. When revenue metering is installed by the Interconnection Customer, the proposed metering installation design must be reviewed and accepted by DEV-ET prior to installation.

If the revenue metering is installed on the secondary side of the Interconnection Customer's step-down transformer, it is to be compensated for losses in the transformer. The revenue metering is to also be compensated for losses in any significant length of conductors between the metering point, the step-down transformer, and the POI.

If Interconnection Customer revenue metering is compensated, the Interconnection Customer is to provide DEV-ET with the following information:

- Certified manufacturer test data for the step-down transformer including nameplate ratings, no-load losses, load losses, exciting current, and impedance.
- Primary side voltage tap setting planned for the step-down transformer if equipped with a no-load tap changer. The transformer test data specified above is to be provided for all available taps.
- Information regarding the conductors on the primary side of the Interconnection Customer's step-down transformer, if applicable, and the secondary side including conductor type, number of conductors per phase, length, resistance, and reactance (in Ohms per conductor per 1000 feet or per mile).
- If DEV-ET specifies compensated revenue metering on the secondary side of a step-down transformer, the Interconnection Customer may install the CTs and VTs in any one of the following configurations after DEV-ET review and acceptance of the proposed design:
  - An outdoor overhead metering structure with visible break switches or disconnects on both the incoming and load sides.
- Pad mounted metering enclosure with dead-front disconnecting elbows on both the incoming and load sides.
- Switchgear metering compartment with a visible break switch or disconnect on both the incoming and load sides. The compartment must be sealable with doors on the front and back. The CTs and VTs can be picked up from the closest DEV-ET office to the interconnecting site. The Interconnection Customer must provide DEV-ET with detailed metering compartment drawings (front, side, and rear views) that show the orientation of the CTs on the bus work and indicate electrical clearances. There must be adequate working clearances around the CT and VT secondary terminal boxes for DEV-ET meter personnel to install the secondary wires.

For end-user Interconnection Customer's Facility with behind-the-meter generation, DEV-ET may require the Interconnection Customer to install, own, operate, test, and maintain additional revenue metering at the output of the generation equipment, which is to meet any requirement specified in the applicable tariffs or interconnection agreements. If Interconnection Customer owned metering is installed, the Interconnection Customer is to also provide DEV-ET with the generation revenue metering data if required.

When the end user has non-conforming load, a primary revenue meter along with SCADA data is required. Non-conforming load is load of more than 50 MW that exhibits one of more of the following characteristics:

- Expected load swings of approximately 50 MW or more and ramp rates of approximately 10 MW or more per minute

Loads with expected daily reactive power ramp rates of 50 MVAR or more per minute

- Loads that may create voltage flicker exceeding the limits set out in the Institute of Electrical and Electronics Engineers (IEEE) Standard 1453

Loads that may create voltage flicker exceeding the limits set out in the Institute of Electrical and Electronics Engineers (IEEE) Standard 1453

- Loads that may create harmonic current distortions exceeding the limits set out in IEEE Standard 519

4.1.6.7 *Telecommunications*

In recognition that the coordination of the system operations by the Parties may be facilitated by the sharing of power flow and other real-time information from meters and other equipment at the Interconnection Points, the Parties may agree to cooperate on the installation and operation of data acquisition system ("DAS") equipment including, but not limited to, remote terminal units (RTU"), meters, MW/MVAR and Volt transducers, telecommunication devices, lease lines, and any related equipment at points which from time to time are to be mutually agreed upon.

If a backup telemetry system or data is required by one Party for their own use, the requesting Party is to be responsible for installing and/or maintaining the field devices and associated telecommunication system at their cost.

The following real-time operational data is to be provided to all Parties as available: three phase bi-directional energy flows (e.g., MWh, MVARh), three phase instantaneous power flows (e.g., MW, MVAR), per phase RMS voltages, and per phase RMS currents with at least two decimal points resolution is to be provided. In addition to the real-time operational data, the status of all switching devices associated with the interconnection circuit(s) are to be provided. The real-time data requirements defined in the PJM manuals, including PJM Manual 01 – Control Center and Data Exchange Requirements and PJM Manual 03 – Transmission Operations, is to be provided to PJM to fulfill its roles as Reliability Coordinator (RC), Balancing Authority (BA), and Transmission Operator (TOP).

Metering, Data, and Communications requirements between a generation Facility and PJM are resolved in the kickoff meeting between the PJM client manager and the generation owner, as described in §4.2.2 of PJM Manual 14D – Generator Operational Requirements.

For generation Facilities that interconnect to DEV-ET via generator interconnection stations, serial telemetry data exchange is required between the two facilities. The Data Exchange and Communications requirements between a generation Facility and the DEV-ET interconnection station are specified in Attachment 5, Electric Transmission Generator Interconnection Data Communication and Data Exchange Requirements.

4.1.7 *Grounding and Safety Issues*

All electrical equipment, electrical components, fences, metal buildings, protective controls, and structures are to be properly grounded and bonded. A safe grounding design must accomplish two basic functions:

4.1.7.1 Personnel safety: Ensure that Facility personnel, their contractors and the public are not exposed to harmful step-and-touch potentials.

4.1.7.2 Current path to earth: Provide a path for electric currents into the earth under normal and fault conditions. Under normal conditions currents do not exceed any operating and equipment limits. Under fault conditions the currents do not adversely affect the continuity of service.

Accordingly, each electrical Facility must have a grounding system or grid that solidly grounds all metallic structures and equipment in accordance with standards outlined in the latest revisions of IEEE 80, IEEE Guide for Safety in AC Substation Grounding, and IEEE C2, National Electrical Safety Code (NESC).

Designs must ensure that step and touch potentials and transferred voltages are limited to safe levels. Furthermore, testing must be performed to verify the integrity of the installed grounding system and ensure safe step and touch potential parameters have been met in accordance with the latest revision of IEEE 80.

When various switching devices are opened on an energized circuit, its ground reference may be lost if all sources are not effectively grounded. This situation may cause over voltages that can affect personnel safety and damage equipment. This is especially true when one phase becomes short-circuited to ground. Therefore, the interconnected transmission power system is to be effectively grounded from all sources. This is defined as:

$$Xo/X1 \le 3$$

$$Ro/X1 \le 1$$

This relationship assumes R1/X1 = 0, which is a worst-case condition.

Interconnected generators should provide for effective system grounding of the high-side transmission equipment by means of a grounded high-voltage generation step-up transformer.

Shield wires should be considered, where applicable, to protect conductors and equipment from lightning strikes. A recommendation for maximum resistance values for all new stand-alone (not connected to a ground grid) structures carrying shield wires are as follows: 25 Ohms for structures supporting Facilities at or below 230kV, and 20 Ohms for structures supporting Facilities from above 230kV to 500kV.

Safety is of utmost importance. Any work conducted within a Facility is to be performed in accordance with all applicable laws, rules, and regulations and in compliance with

Occupational Safety and Health Administration (OSHA), NESC, and Good Utility Practice. Automatic and manual disconnect devices are to be provided as a means of removing all sources of current to any Element of the power system. Only trained operators are to perform switching functions within a Facility under the direction of the responsible dispatcher or designated person as outlined in the NESC. The Interconnection Customer and DEV-ET must agree to switching and Lock Out/Tag Out procedures that are adhered to for the safety of all personnel. DEV-ET follows its own standard operating practices and grounding procedures for safety of personnel.

4.1.8 *Insulation and Insulation Coordination*

Insulation coordination is defined by IEEE 62.82.1 as "The selection of insulation strength of equipment in relation to the voltages, which can appear on the system for which equipment is intended and taking into account the service environment and the characteristics of the available protective devices." Insulation coordination must be designed properly both for personnel safety and to protect the electrical equipment from the harmful over-voltages resulting from faults, lightning or switching transients. An insulation design must accomplish two basic functions:

- Electrical isolation: Electrically isolate the maximum anticipated voltage of energized parts from supporting structures or ground.
- Mechanical support: Mechanically support energized parts as intended.

Surge arresters and static wires are used to safeguard the electric power equipment against harmful over-voltages. Basic Impulse Levels (BIL) for electrical equipment and high voltage substation buses are to meet or exceed DEV-ET's standard listed below:

Nominal KV (phase to phase)	Basic Impulse Level (BIL)
115	550
138	650
230	900
500	1550

Equipment BIL shielding and surge protection is to be designed as determined by lightning and switching surge analysis to meet all applicable ANSI/IEEE standards and DEV-ET and substation engineering standards.

DEV-ET Specifications for Transmission Line Insulators include:

- TE VEP 1115 – Porcelain and Glass Insulators
- TE VEP 1117 – Suspension Type Non-Ceramic Insulators
- TE VEP 1118 – Non-Ceramic Post Type Insulators

ANSI/IEEE standards include, but are not limited to:

- ANSI C29 collection of standards – Insulators for Electric Power Lines

Interconnection Facilities to be constructed in areas with salt spray contamination or other types of contamination are to be properly designed to meet or exceed the performance of Facilities in a non-contaminated area. Typically, this involves more insulation, higher leakage distances and/or non-standard insulating components and materials.

The following is to be submitted, as applicable, with the Customer Request Form, provided in Attachment 2, for evaluation as part of the interconnection plan:

- Surge arrester ratings
- Basic switching surge levels
- Surge arrester, conductor spacing and gap application
- Substation and transmission line insulation strength
- Protection and/or shielding schemes
- Overhead static wire location
- Equipment BIL ratings
- Insulator BIL ratings

4.1.9 ***Voltage, Reactive Power, and Power Factor Control***

4.1.9.1 *Generation Facilities*

PJM is responsible for ensuring the stability and reliability of its electric transmission system. In turn, all generation Interconnection Customers are responsible for operating their units in a stable manner while those units are connected to DEV-ET's Facilities. Generator excitation and prime mover controls are key Elements in ensuring electric system stability and reliability. To meet its responsibility, PJM must have the ability to establish voltage and governor control requirements for all generators connected to its system, including units connected through DEV-ET's Facilities. These requirements may vary depending on the location, size, and type of generation installed.

Generator Interconnection Customers are required, with oversight by PJM, to follow the current NERC and SERC standards and guides for generator operation, protection, and control.

- All synchronous generators connected to the interconnected transmission systems are to be operated with their excitation system in automatic voltage control mode unless approved otherwise by PJM. PJM and DEV-ET is to be notified any time a generator control system is removed from service, or its logic is modified. These control systems may include, but are not limited to, voltage regulators, power system stabilizers, governor, and prime mover controls.

- Generators are to maintain a network voltage or reactive power output as required by DEV-ET, with governance by PJM, within the reactive capability of the units. Generator step-up and auxiliary transformer are to have their tap settings coordinated with electric system voltage requirements.
- All new inverter-based resources (IBRs), such as wind and solar, connecting to the DEV-ET system must have the capability to provide leading and lagging reactive power including, but not limited to, nighttime Volt-Amperes Reactive (VAR) support. Duration that the generating Facility can operate in a VAR supporting mode is to not be limited by any other Facility component. Prior to Facility commissioning for IBRs, any logic associated with VAR capability must be enabled and turned on such that an operator can readily control the Automatic Voltage Regulator (AVR) voltage setpoint via the DEV-ET SCADA system. During commissioning, daytime, and nighttime VAR testing, in addition to AVR test results, must be completed and documented. This testing must also include transitions from day-to-night and night-to-day and charging/discharging/idle mode for battery storages. Both daytime and nighttime VAR and AVR testing results must be submitted to the DEV-ET System Operations Center. The requirements for the DEV-ET SCADA voltage setpoint control function are further detailed in Attachment 5, Generator Interconnection Data Communication and Data Exchange Requirements. Control Narrative, explicit point definitions, and data communications requirements for this function are thoroughly established in Attachment 5.
- Temporary excursions in voltage, frequency, and real and reactive power output that a generator is to be able to sustain is to be defined and coordinated on a regional basis.
- Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) are to coordinate with the generator's short duration capabilities and protective relays.
- Prime mover controls (governors) are to operate with appropriate speed/load characteristics to regulate frequency.

All interconnected generation must adhere to power factor requirements for new generator interconnection requests and increase to existing generators as documented in PJM Manual 14G – Generation Interconnection Requests, Section 4: Generator Interconnection Requirements, Rights and Obligations. Asynchronous generators connected to the transmission systems are to be studied in the PJM System Impact Study to determine the reactive power compensation required. All interconnected generation must meet the following criteria:

- All synchronous and asynchronous generators connected to the interconnected transmission systems are to maintain a power factor of at least 0.95 leading to 0.95 lagging measured at the Point of Interconnection.
- All new intermittent, asynchronous generators interconnecting to the transmission system that cannot provide control of real power output (wind,

solar) are studied for reactive power capabilities in a manner that considers the variability of the entire intermittent generation fleet within the DEV-ET footprint; DEV-ET provides input and support these studies if deemed necessary, following these requirements.
- Voltages at the Point of Interconnection of any generating station should not vary more than 1.0% for expected changes in generation output caused by fluctuations in the prime mover output.
- The System Impact Study for asynchronous, intermittent generation considers the generator under study as well as variability of the entire intermittent generation fleet when determining if the voltage fluctuation criteria is met.
- New variable generation resources that cannot meet the 1% voltage deviation criteria provide dynamic reactive compensation as specified in the PJM System Impact Study, with DEV-ET support and studies incorporated.

Specific requirements for voltage regulators, power system stabilizers, governor controls, and remote control and telemetry of such devices are determined during the System Impact Study. These specific requirements for a generator will be part of the Interconnection Service Agreement. (PJM Manual 14A, Section 5: Summary of Agreements).

4.1.9.2 *Transmission Facilities*

The Transmission System must be capable of moving electric power from areas of generation to areas of load under a wide variety of expected system conditions. Adequate reactive power supplies are of paramount importance to the capability of the Transmission System to reliably support a wide variety of transfers. Transmission Facilities must be designed to minimize excessively high voltages during light transmission loading conditions yet have adequate reactive supplies to support system voltage during heavy transmission loading conditions.

4.1.9.3 *End-User Facilities*

The voltage variation limitations for interconnections with End-User Facilities are as stated in the applicable tariff or agreement. End-User Facilities connected directly to the Transmission System should plan and design their systems to operate at close to unity power factor to minimize the reactive power burden on the Transmission System.

4.1.10 ***Power Quality Impacts***

4.1.10.1 *Flicker Requirements*

Flicker is assessed at the Point of Common Coupling (PCC) using an instrument in compliance with International Electro Technical (IEC) 6100-4-15.

The flicker measured at the PCC is to be 0.8 or less for the short-term flicker (Pst) and 0.6 or less for the long-term Flicker (Plt). The Pst and Plt values measured are not to exceed more than 1% of the time based on a probability distribution calculated for a one-week period.

4.1.10.2 *Harmonic and Inter-Harmonic Requirements*

Harmonic levels are assessed at the PCC with an instrument that can take individual samples of voltage and current waveforms and determine the probability distribution of the individual harmonic levels for both the current and the voltage. Harmonic distortion levels at the PCC should meet the requirements contained in the latest revision of IEEE Standard 519.

In addition, the individual inter-harmonic currents are to be limited to 25% of the values in IEEE Standard 519 and the THD (Total Harmonic Distortion) and TDD (Total Demand Distortion) calculation is to include the inter-harmonic components. The Inter-harmonics are to be calculated in 10 Hz increments. The current distortion levels specified in IEEE Standard 519 is to not exceed more than 5% of the time based on a probability distribution calculated for a one-week period.

4.1.11 ***Equipment Ratings***

Electrical equipment and associated interconnected Facilities are to be capable of safely interrupting the worst-case short circuit faults calculated for the protection zone.

All current-carrying equipment and devices are to be designed to carry the maximum loads that are predicted and used in load flow analysis, tested against all applicable NERC Reliability Standards, PJM Transmission Planning Criteria and DEV-ET Planning Criteria. Loads exceeding nameplate or normal design capacities are acceptable only when allowed by manufacturers' design documentation or standard industry practice or by DEV-ET's Facility Rating Methodology (FRM).

Circuit breakers and disconnect switches are to be designed and tested according to the latest IEEE C37 collection of standards. Power transformer and Instrument transformers are to be designed and tested according of IEEE C57 standards. Rigid bus structures are to be designed to meet the latest revision to IEEE 605. Current carrying conductors and tubing are to be braced and supported for the expected worst case, short circuit currents, ice loading and wind loading. For overhead line Facilities, ground clearance is to be maintained according to the latest IEEE C2, National Electrical Safety Code (NESC). All Facilities at voltages greater than 230kV should be considered Extra High Voltage (EHV) and designed accordingly.

Equipment Basic Impulse Levels (BIL), shielding, and surge protective device application must meet requirements as determined by the latest IEEE C62 standards. DEV-ET provides the BIL for the system in the interconnection area. Also, equipment must meet all applicable ANSI/IEEE standards and specifications communicated by PJM and DEV-ET. BILs for electrical equipment and high voltage substation buses are to meet or exceed DEV-ET's standard listed below.

Nominal KV (phase to phase)	Basic Impulse Level (BIL)
115	550
138	650
230	900
500	1550

4.1.12 ***Synchronizing of Facilities***

Synchronizing equipment consisting of potential devices and associated protective relay and controls is required on Facilities where energy can be sourced on both sides of an interconnection circuit breaker. The Interconnection Customer is to not synchronize with the Transmission System prior to obtaining approval from DEV-ET.

The following explains the various synchronizing options.

4.1.12.1 *Generation Facilities*

Live line, dead bus (LLDB) control is used in the interconnection circuit breaker reclosing scheme when generation Facilities are connected to DEV-ET. The circuit breaker cannot be closed unless the generation side has zero voltage. The interconnection circuit breaker should not be used to synchronize a generator to the Transmission System. Instead, the generation Facilities should have their own synchronizing Facilities. In the event a generation Interconnection Customer's Facility becomes disconnected from DEV-ET's system, it is to remain disconnected until system voltage and frequency are within an established range. In all scenarios, DEV-ET is to retain operational control of the interconnection breaker.

4.1.12.2 *Interconnected and Separate Systems for Generators*

The Interconnection Customer may elect to run its generator in parallel (interconnected) with DEV-ET or as a separate system with the capability of nonparallel load transfer between the two independent systems. The two methods of operation are outlined as follows:

Parallel System

A parallel system is one in which the Interconnection Customer's generation equipment can be connected to DEV-ET's system resulting in a transfer of power between the two systems. A consequence of such parallel operation is that the parallel generator becomes an electrical part of the DEV-ET system, which must be considered in the operation and protection of DEV-ET's Facilities. The general and specific requirements for parallel generation installations are discussed in this document.

Synchronizing equipment consisting of potential transformers and associated protective relaying/controls is required on Facilities where energy can be sourced on both sides of an interconnection circuit breaker. This equipment serves the following purposes:

- Verifies the voltages on both sides of a circuit breaker fall within set tolerances, which must meet DEV-ET's approval, as to the magnitude and phase angle established by system conditions
- Supervises the closing and automatic reclosing of the circuit breaker
- Prevents the closing of the circuit breaker when the two systems are out of sync Voltage magnitudes, phase angles, and frequency constraints are to be determined on a case-by-case basis.

Separate System with Non-parallel Load Transfer Capability

A separate system is one in which there is no possibility of delivering energy to the DEV-ET system from the Interconnection Customer's equipment. The Interconnection Customer may maintain the capability of transferring load between the two systems, but such transfer must be accomplished in an open-transition or nonparallel mode. This can be accomplished by either an electrically or mechanically interlocked switching arrangement that precludes both the switch connecting the load to DEV-ET's system and the switch connecting the load to the Interconnection Customer's generation being in the closed position simultaneously. If the Interconnection Customer has a separate system, the Interconnection Customer is to not operate the generation until DEV-ET has verified that the transfer scheme meets the nonparallel requirements. This verification is accomplished by review and approval of drawings and equipment specifications by DEV-ET and, if DEV-ET so elects, by field inspection of the transfer scheme. DEV-ET is not responsible for approving the Interconnection Customer's generation equipment and assumes no responsibility for its design or operation.

4.1.13 **Maintenance Coordination**

4.1.13.1 *Testing*

DEV-ET requires interconnecting entities with protection systems which coordinate with DEV-ET network protection systems to have a documented maintenance program for those systems in accordance with NERC Reliability Standard PRC-005 requirements. Documentation of the maintenance program is to be supplied to DEV-ET upon request. Additionally, the interconnecting entity, on maintenance intervals identified within their documented program and following any apparent malfunction of the protection equipment, is to perform and document both calibration and functional trip tests of its protection equipment as outlined within its maintenance program. Customer is to maintain evidence of such activities and make them available to DEV-ET upon request.

4.1.13.2 *Coordination*

DEV-ET may remove its lines and associated equipment from service for testing of relays and maintenance of lines or substations in accordance with its maintenance program. The Interconnection Customer, DEV-ET, and PJM coordinate for these planned outages.

The interconnection parties agree to confer regularly to coordinate the planning, scheduling, and performance of preventative and corrective maintenance on the Interconnection Customer's Facility, the Interconnection Facilities and associated Facilities owned by DEV-ET. The Interconnection Customer must coordinate its approach and schedule for maintenance and testing with DEV-ET to ensure the reliability of the BES.

4.1.13.3 *Generator Interconnection*

On occasion, the generation Interconnection Customer may not be allowed to operate in parallel with the DEV-ET or distribution system. A generator Interconnection Customer with multiple interconnection points may be permitted to operate only in parallel with specific lines so DEV-ET can perform "live line maintenance" on the Facilities serving the generator Interconnection Customer. The generator Interconnection Customer, DEV-ET and, as needed, PJM, coordinate with these conditions and requests.

4.1.14 ***Operational Issue (Abnormal Frequency and Voltage)***

PJM is the Transmission Operator for DEV-ET System. The Interconnection is operated consistent with PJM requirements and procedures. Specific transmission conditions and procedures for operation of Transmission Facilities (defined by PJM) within PJM are found in PJM Manual 03 – Transmission Operations on the PJM website (www.pjm.com).

4.1.15 ***Load Shed Program as Required by PJM***

The transmission system is designed to automatically activate a load-shed program as required by PJM in the event of an under-frequency system disturbance. A generation Interconnection Customer is to implement under-frequency and over-frequency relay set points for the generation Interconnection Customer as required by PJM to ensure 'ride through' capability of the transmission system. The generation Interconnection Customer Facility is to stay connected to and synchronized with the Transmission System during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice. For more information on ride through requirements of inverter-based generation, see Attachment 4, DEV Bulk Power System Generator Ride-Through Requirements. In addition, additional information is found in PJM Manual 14D –

Generator Operational Requirements. The response of a generation Interconnection Customer's Facility to frequency deviations of predetermined magnitudes; both under-frequency and over-frequency deviations are studied and coordinated with PJM in accordance with Good Utility Practice. Additional information is found in PJM Manual 14D – Generator Operational Requirements. Inspection requirements for new or materially modified existing Interconnections.

DEV-ET has established inspections as a component of its maintenance program for DEV-ET's owned assets. DEV-ET may require right of access to the Interconnection Customer's Facility for purposes of conducting inspections: to include observing tests, visual inspections, and auditing maintenance and testing records.

Additionally, DEV-ET may require right of access to conduct initial (pre-operational) inspection and/or require copies of pre-operational procedures and test reports.

Each party is to, at its own expense, have the right to observe the testing of any of the other party's metering equipment whose performance may be expected to affect the accuracy of the observing party's telemetry and revenue. If requested, each party is to notify the other in advance of metering or other equipment testing and maintenance and may have a representative attend and be present during such testing.

If DEV-ET identifies any deficiencies, defects, or inconsistencies of the Interconnection Customer's Facility that may adversely affect the reliability of the bulk power system and/or potentially constitute a compliance concern for DEV-ET, then DEV-ET is to provide notice to the Interconnection Customer outlining the concern and the suggested corrective action. Customer is to provide DEV-ET with a corrective action plan resolving identified concern(s).

If Interconnection Customer observes any deficiencies, defects, or inconsistencies of its Interconnection Facility that may adversely affect the reliability of the bulk power system and/or potentially constitute a compliance concern for DEV-ET, then the Customer is to provide notice to DEV-ET outlining the identified concern and the corrective actions that are taken to resolve the concern.

4.1.16 ***Communications and Procedures During Normal and Emergency Operating Conditions***

Complete, precise, and timely communication is an essential element for maintaining reliability and security of a power system. Under normal operating conditions, the major link of communication with various interconnects is to be by telephone lines. DEV-ET and the Interconnection Customer is to maintain communications which are to include, but not be limited to exchanging up-to-date information regarding:

- Contact information for maintenance personnel
- Maintenance schedules
- Meter tests
- Relay tests
- System paralleling or separation

- Scheduled or unscheduled shutdowns
- Equipment clearances
- Periodic load reports
- Tagging of Interconnection interrupting devices
- Billing
- Other routine communication

In case of emergency or abnormal operating conditions, various communication channels may be used depending on the interconnect category. Emergency telephone numbers should be agreed upon by both parties prior to the date of initial Interconnection. Each Interconnection party is to notify the other parties promptly when it becomes aware of an emergency condition that may be expected to affect operation of the Interconnection Customer's Facility, the Interconnection Facilities, the DEV-ET Interconnection Facilities, or the Transmission System.

4.1.17 ***Generation and Transmission Interconnection Customer Obligations***

Generation and transmission Interconnection Customers are to install and maintain satisfactory operating communications with PJM's system dispatcher or its other designated representative and with DEV-ET system dispatcher. Generation and transmission Interconnection Customers are to provide standard voice line, dedicated voice line, and facsimile communications at their Facility control room through use of the public telephone system. Generation and transmission Interconnection Customers also are to provide and maintain backup communication links as specified by both PJM and DEV-ET for use during abnormal conditions. Satellite phones compatible with PJM and DEV-ET equipment should be available for emergency communications. Generation and transmission Interconnection Customers further are to provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to PJM and DEV-ET as necessary to conform to applicable technical requirements and standards.

4.2 Transmission Line Connections – Generation

Transmission Facilities may be used for providing service to generation developers when the use of distribution feeders is not practicable. The use of transmission Facilities should be considered for the following conditions:

- All generating Facilities over 20 MW
- Locations remote from distribution Facilities
- Remote locations where distribution Facilities are not adequate

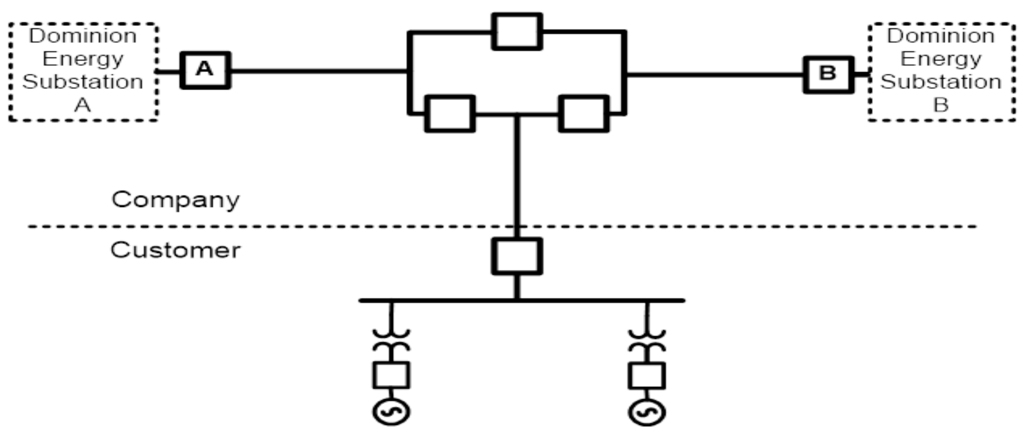
For Interconnection to the 500kV network, the preferred minimum generation capability at a single point of connection is 500MW. The Interconnection of generating plants on the 500kV network below this level are permitted for cases where no other lower transmission voltage option is available.

The descriptions and diagrams in this section are typical from an Interconnection standpoint; they are subject to further modification as necessary to comply with Attachment 3 - DEV Generator Interconnection Protection Requirements, Section 3 - Interconnection Protection Requirements.

4.2.1 ***Single Circuit Interconnection to a Transmission Line***

A transmission line tap, as shown in Diagram 6.1, can generally be used to interconnect a proposed new generating Facility of any size located within one mile, or a generating Facility of 500 MW or less located at a distance greater than one mile to the Transmission System. With this arrangement, loss of generation does not interrupt flow on the Transmission System and loss of a transmission line does not result in loss of generation. However, final System Protection requirements along with Interconnection substation requirements are to be based on the reliability impact conducted through the PJM Interconnection Queue process as defined in PJM Manual 14C – Generation and Transmission Interconnection Facility Construction. The customer should reserve property for construction of the DEV-ET -owned Interconnection station.

Diagram 4.2.1: Line Tap – Generation adjacent to transmission line



Notes:

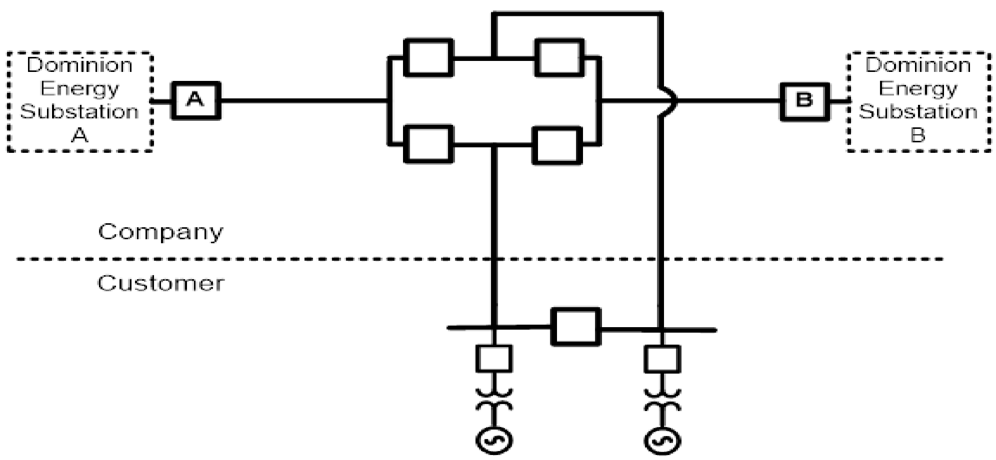
Specific violation of the criteria outlined in Section C of Attachment 1, DEV-ET Planning Criteria, may require a four-breaker ring bus.

See Section 4.2.5 for additional acceptable breaker configurations.

4.2.2 ***Transmission Interconnections Located Remote from a Transmission Line***

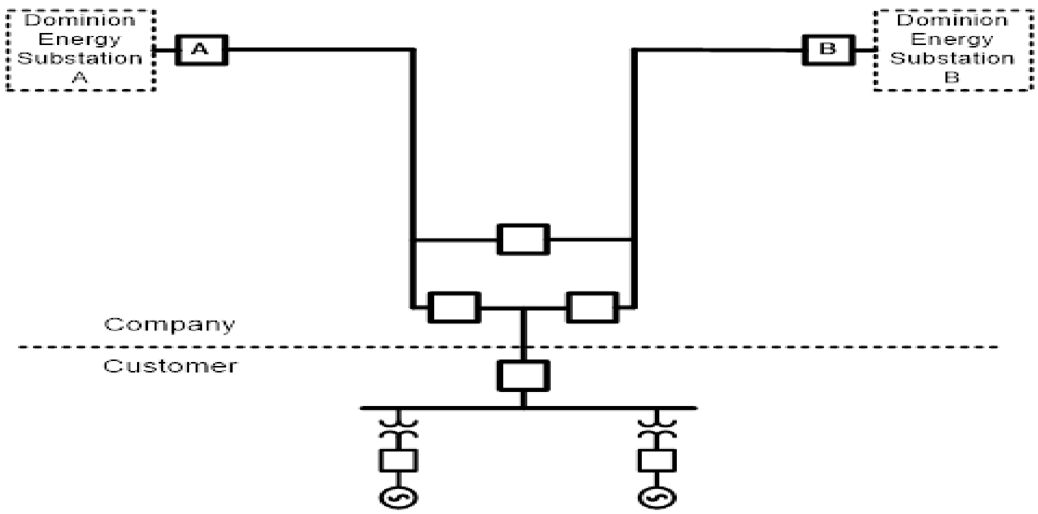
If the proposed Generating Facility is greater than 500 MW and located more than one mile from an existing transmission line, then the proposed arrangement shown in Diagram 6.2.A or 6.2.B could be used. With this arrangement, loss of generation does not interrupt flow on the Transmission System and loss of a transmission line does not result in loss of generation. However, final System Protection requirements along with Interconnection substation requirements are to be based on the reliability impact conducted through the PJM Interconnection Queue process as defined in PJM Manual 14C – Generation and Transmission Interconnection Facility Construction.

Diagram 4.2.2.A: Line Tap – Large generation located remote from transmission line



As an alternative to constructing a switching station at the tap point, the transmission line can be cut and looped in and out to a switching station located adjacent to the generating station as shown in Diagram 6.2.B. This arrangement can have its advantages since acquiring land and permitting a new station at the tap point would not be required. The customer should reserve property for construction of the DEV-ET owned Interconnection station.

Diagram 4.2.2.B: Looped Tap – Large generation located remote from transmission line



Notes:

Specific violation of the criteria outlined in Section C of Attachment 1 - DEV-ET Planning Criteria of this document may require a four-breaker ring bus.

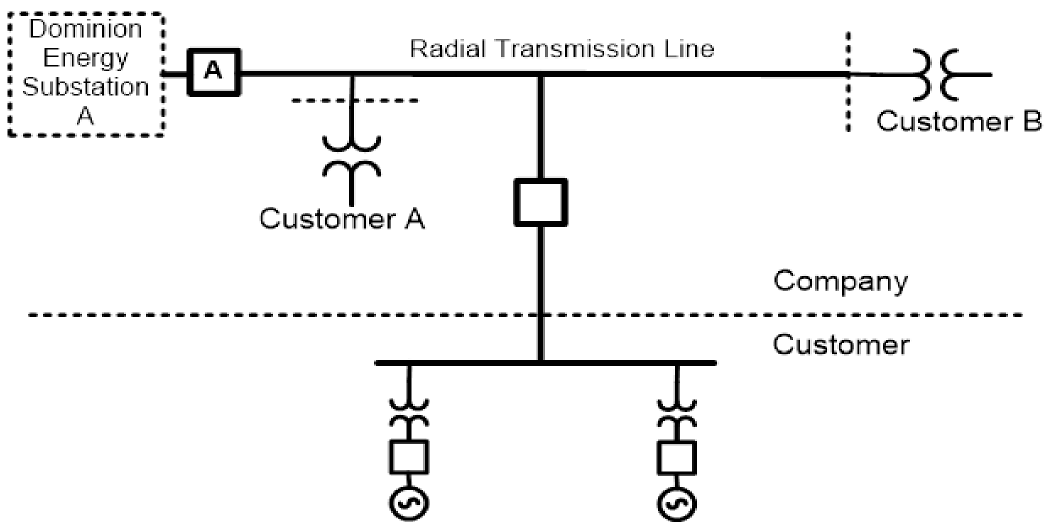
See Section 4.2.5 for acceptable arrangements for Interconnection breaker.

4.2.3 ***Interconnection to Radial Transmission Line or Radial Transmission Tap***

4.2.3.1 *Connection to Radial Transmission Line*

A proposed generating Facility may be connected to a radial transmission line. A radial transmission line is defined as a single line that has one transmission source and does NOT tie to any other transmission network source (line or substation).

Diagram 4.2.3.1 – Connection to radial transmission line



4.2.3.2 A proposed generating Facility may be connected to a transmission tap line portion of a network transmission line, as shown in diagrams 6.3.2.A and 6.3.2.B, subject to Attachment 3 -DEV Generator Interconnection Protection Requirements, Section 3 Interconnection Protection Requirements.

Diagram 4.2.3.2.A – Connection to radial transmission tap line (single point)

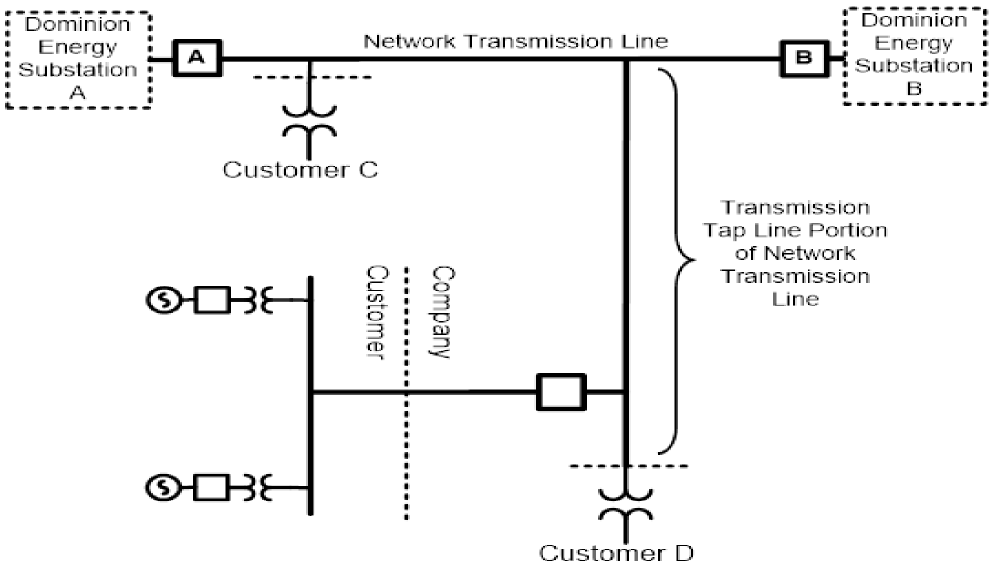
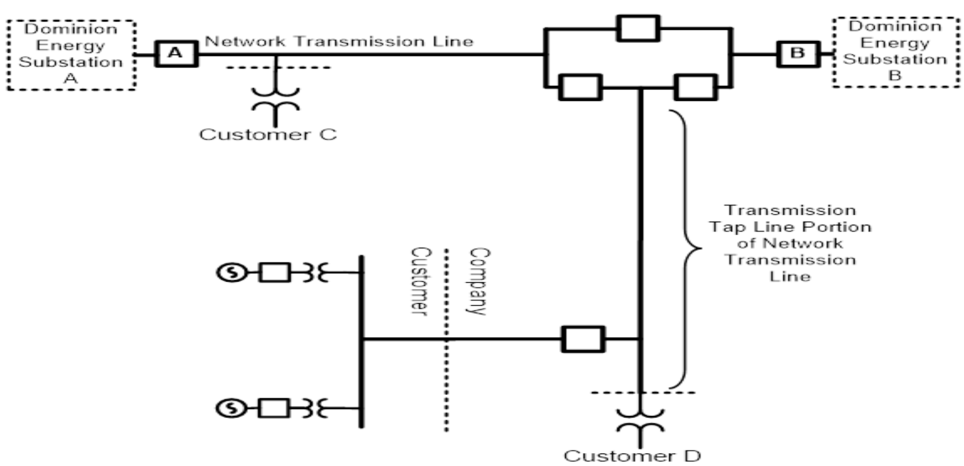


Diagram 4.2.3.2.B – Connection to radial transmission tap line (ring bus)



4.2.4 ***Substation Interconnection Requirements***

All generation interconnection substation designs include all switches and devices required to permit maintenance of all breakers and transmission lines without the loss of the ability to use the generation capacity when required. Small units can be bussed together behind breakers unless reliability studies indicate issues.

4.2.5 ***Transmission Interconnection Breakers***

If new transmission lines are required by the addition of generator capacity at a new or existing power station, the breaker arrangement at the existing substation determines both the number of breakers and the breaker arrangement required for the Interconnection. Line terminations that result in a four breaker or less ring bus are acceptable. If more than a four-breaker ring bus is required, a breaker and a half arrangement would be used for reliability considerations.

4.2.6 ***Generation Interconnection Breakers***

Diagrams 4.2.6.A and 4.2.6.B – Multiple breakers

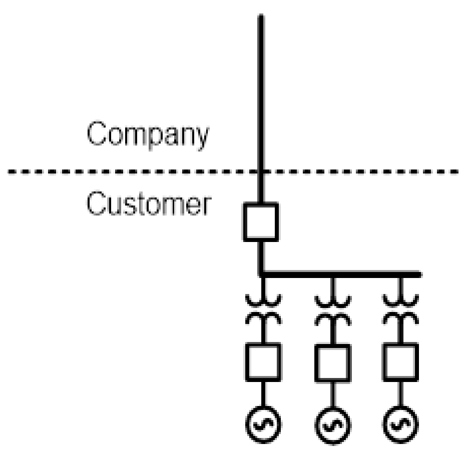


Diagram 6.6.A.

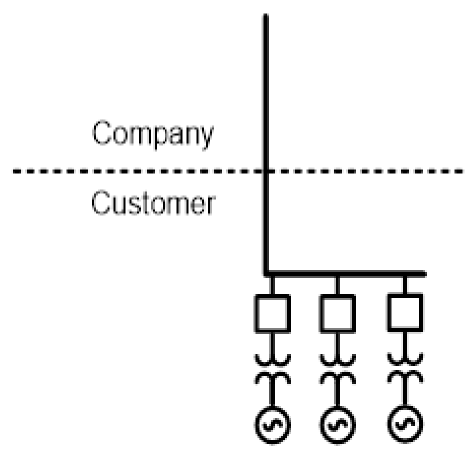


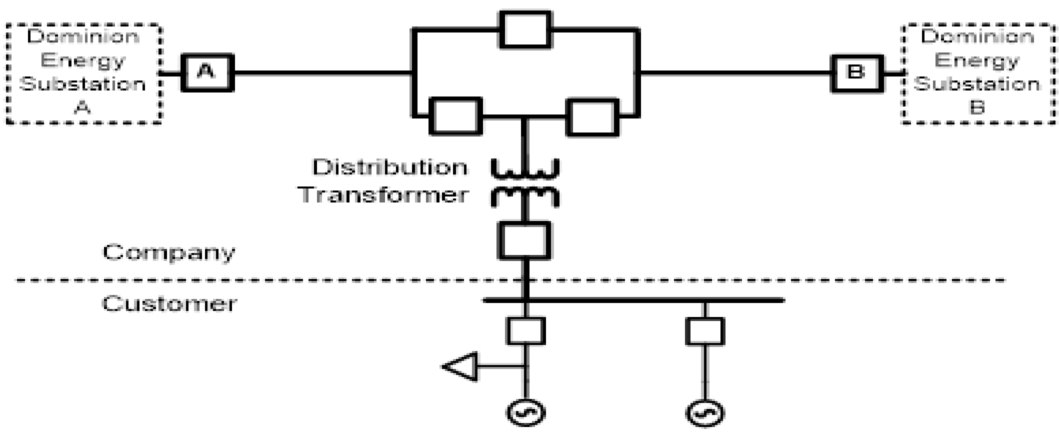
Diagram 6.6.B.

However, regardless of distance, final System Protection requirements along with Interconnection substation requirements are to be based on the reliability impact conducted through the PJM Interconnection Queue process as defined in PJM Manual 14C – Generation and Transmission Interconnection Facility Construction. Interconnection Requirements for Distribution Connected Generation.

The Distribution Connected Generation is defined as a generator who is requesting connection to distribution Facilities serving retail customers (excluding the station service load for the respective generator).

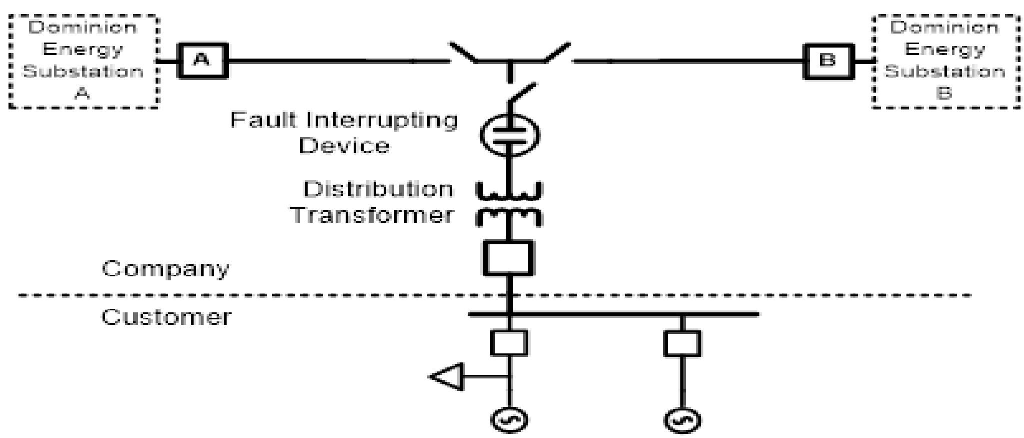
Distribution connected generation resources where the aggregate nameplate rating of all the generating resources (dispersed generation resources) is greater than 100 MVA, require a three-breaker ring at the point of connection to the transmission system.

Diagram 4.2.6.C Distributed Generation greater than 100MVA



Distribution connected generation resources where the aggregate nameplate rating of all the generating resources (dispersed generation resources) is less than 100MVA can be connected behind a single interrupting device (circuit breaker or circuit switcher).

Diagram 4.2.6.D Distributed Generation less than 100MVA



4.3 Load Criteria – End User

Transmission Facilities may be used for providing service to commercial, industrial, municipal, cooperative and cogeneration customers when the use of distribution feeders is not practicable. The use of transmission Facilities should be considered for the following conditions:

- All loads over 20 MW
- Locations remote from distribution Facilities
- Remote locations where distribution Facilities are not adequate
- Loads with nonstandard voltage requirements
- Loads having large surge requirements

The following are minimum load levels within the ten-year planning horizon for the direct Interconnection of loads to existing transmission lines:

- 500 kV – Reserved for bulk power transfers
- 230 kV – 30 MW
- 138 kV – 20 MW
- 115 kV – 20 MW

The interconnection of loads below these levels are permitted after a thorough planning analysis concludes that the cost and reliability of distribution alternatives are clearly inferior to the overall cost and reliability of a transmission Interconnection which includes, without limitation, considerations of any transmission reliability or operational concerns that may arise from adding the transmission Interconnection. For consideration of an interconnection of loads below the specified levels, the requesting party is to prepare documentation explaining and supporting why distribution alternatives are inferior and must supply additional documentation which may require DEV-ET to undertake its own analysis.

The feasibility of serving customers direct from the transmission along with determining the final recommended transmission Interconnection Facilities requires a comprehensive study and coordination. Factors to be considered prior to agreeing on a customer connection are as follows:

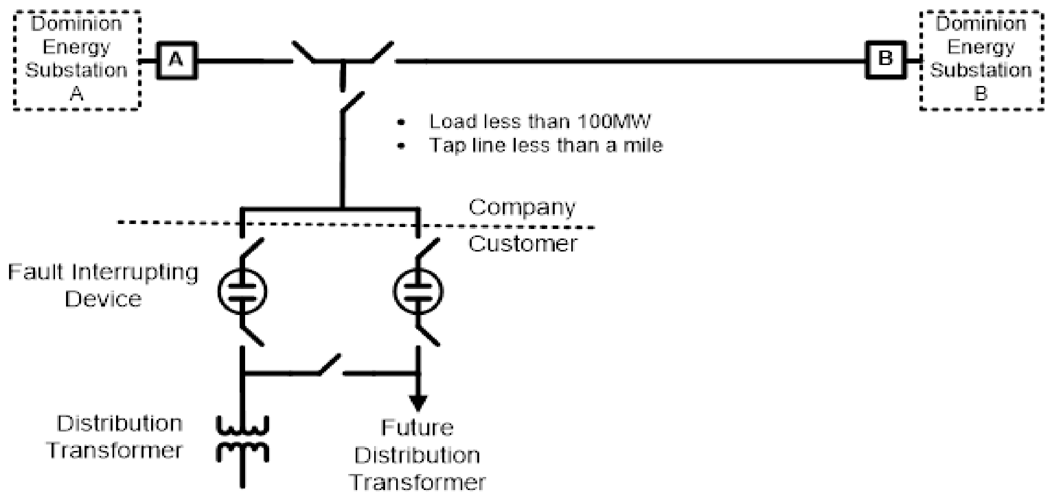
- Economics of distribution versus transmission alternates
- Customer parallel generation
- Transmission line tap or loop length
- Economics of radial line versus looping even when typical thresholds (e.g., length, load level) are not met
- Mitigation of economic risk in the event actual load varies materially from planned load
- Customer transformer characteristics
- Customer switching
- Effect on protective relaying at remote terminals
- Problems of large through power on looped lines
- Extent of customer Facilities

In general, a tap line more than one mile requires a terminal station. If the tap line is long enough to require a terminal substation, a three-breaker or four -breaker ring bus may be required. With these arrangements, loss of line to the customer does not interrupt flow on the Transmission System and loss of a transmission line does not result in loss of service to the customer. The total projected load and MW-Mile[1] exposure are also factors to be taken into consideration. The final number of breakers and breaker arrangement is however based on the specific Interconnection request and reliability impact on Transmission System.

The following typical diagrams indicate the Facilities arrangement for normal service 100 kV and above.

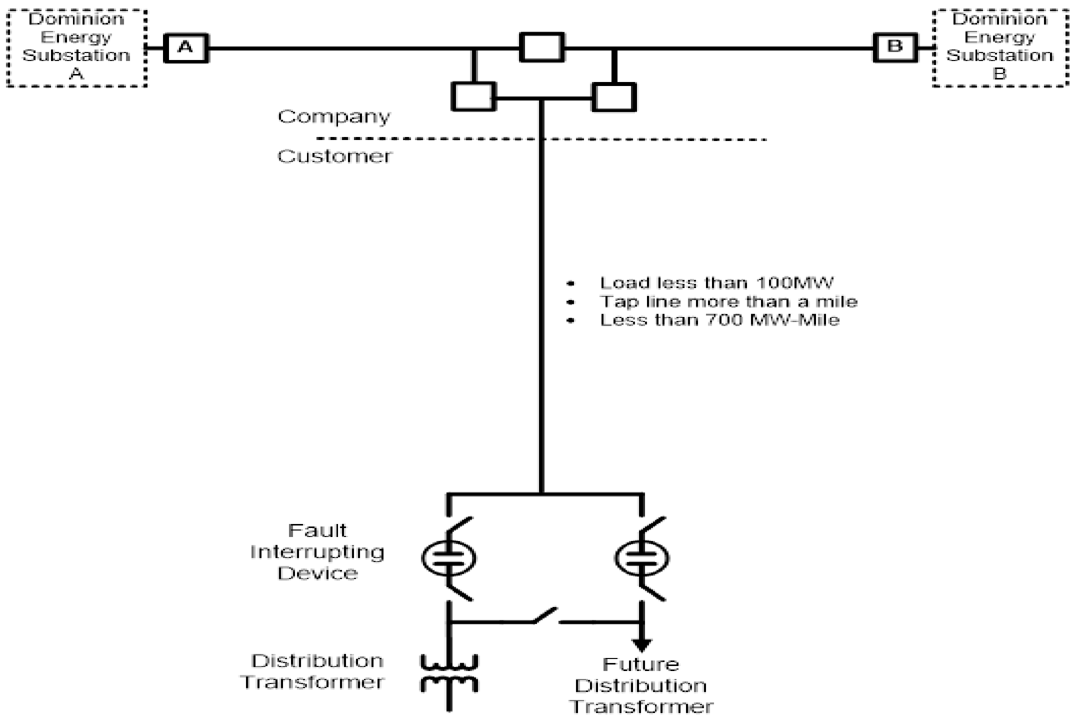
4.3.1 *Tapping Line for Loads Below 100 MW*

Diagram 4.3.A: Tap line for less than 100MW, less than 1 mile



A transmission line tap, as shown in Diagram 4.3.A, can generally be used to interconnect a proposed customer Facility located within one mile or less to the nearest transmission line. With this arrangement, the company installs necessary system protection equipment and associated components at the customer's Facility. The final System Protection and Interconnection substation requirements communicated to the customer are to be based on the site-specific detailed reliability impact as determined by DEV-ET. See Section 4.4 for additional options.

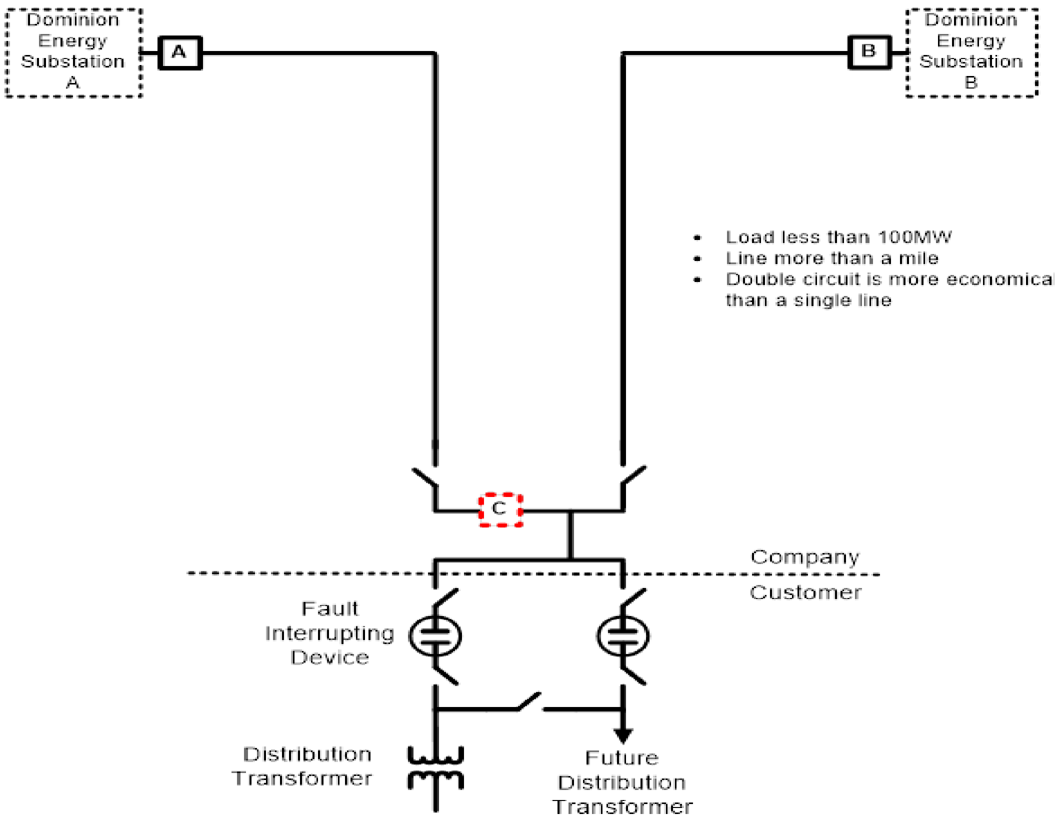
Diagram 4.3.B: Tap line for less than 100MW, more than 1 mile, less than 700 MW-Mile



A transmission line tap, as shown in Diagram 4.3.B, can generally be used to interconnect a proposed customer Facility located more than one mile from to the nearest transmission line. A three-breaker or four-breaker ring bus may be required. With this arrangement, the company installs all necessary equipment at the Interconnection substation at or near the transmission line.

The final System Protection and Interconnection substation requirements communicated to the customer are to be based on the site-specific detailed reliability impact as determined by DEV-ET.

Diagram 4.3.C: Tap line less than 100MW, more than 1 mile, two feeds



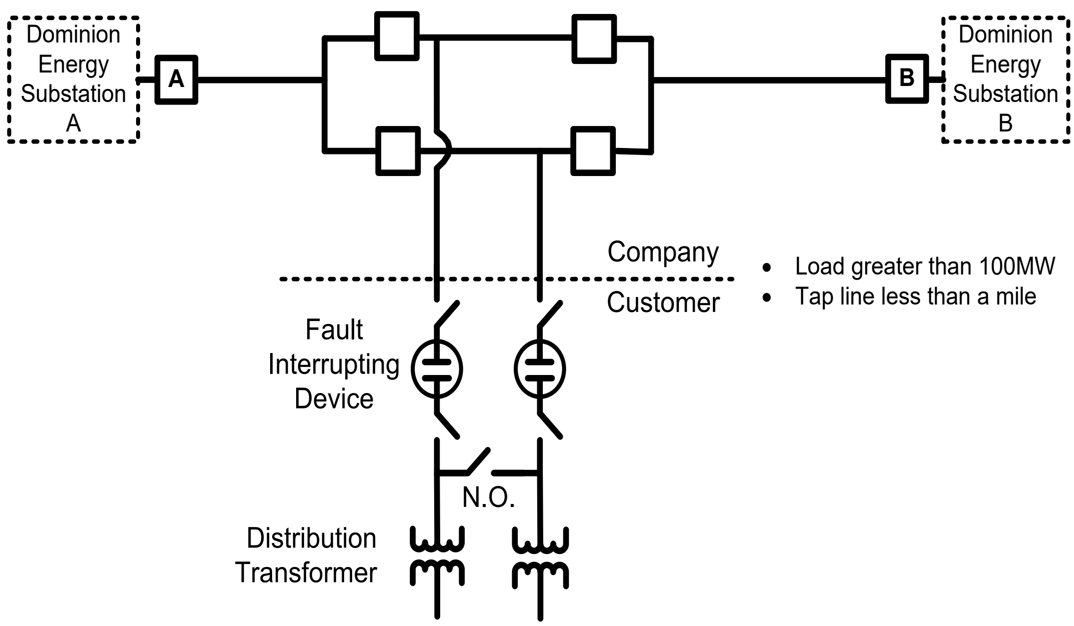
A transmission line tap, as shown in Diagram 4.3.C, can generally be used to interconnect a proposed customer Facility of less than 100 MW and when it is more economical to build double circuit rather than a single line. The customer may reserve property for the DEV-ET owned Interconnection station if one is required.

The addition of breaker "C" may be required to limit the number of direct-connect loads (tapped Facilities) to four, or as otherwise required based on detailed System Protection and Interconnection substation assessments.

4.3.2 *Tapping Lines for Loads 100 MW and Greater*

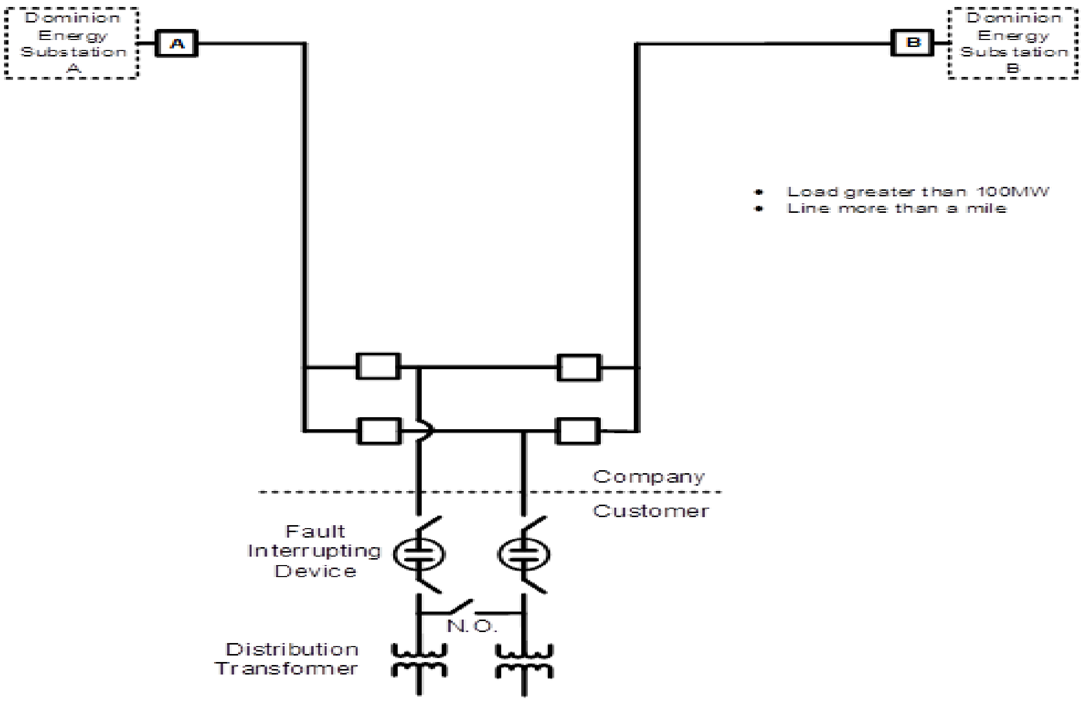
The addition of customer load more than 100 MW should be connected to the Company's Transmission System as shown below in Diagrams 4.3.D and 4.3.E. If available 230kV is the preferred voltage level to connect loads greater than 100MW.

Diagram 4.3.D: Tapping line 100 MW load and greater, less than a mile



A 4-breaker ring bus arrangement as shown in Diagram 4.3.D can generally be used to interconnect a proposed customer Facility of 100 MW and greater having two customer transformers, or to address a specific violation of the NERC standard outlined in Section C of Attachment 1, DEV-ET Planning Criteria. For cases in which there is only one customer transformer, a 3-breaker ring bus may be acceptable. With either arrangement, loss of line to the customer does not interrupt flow on the Transmission System and loss of a transmission line does not result in loss of service to the customer. However, the final System Protection and Interconnection substation requirements communicated to the customer are to be based on the site-specific detailed reliability impact as determined by DEV-ET. The customer could reserve property for construction of the DEV-ET-owned Interconnection station if customer parcel is adjacent to or in very close proximity of transmission right of way.

Diagram 4.3.E: Tapping line 100 MW load and greater, more than a mile



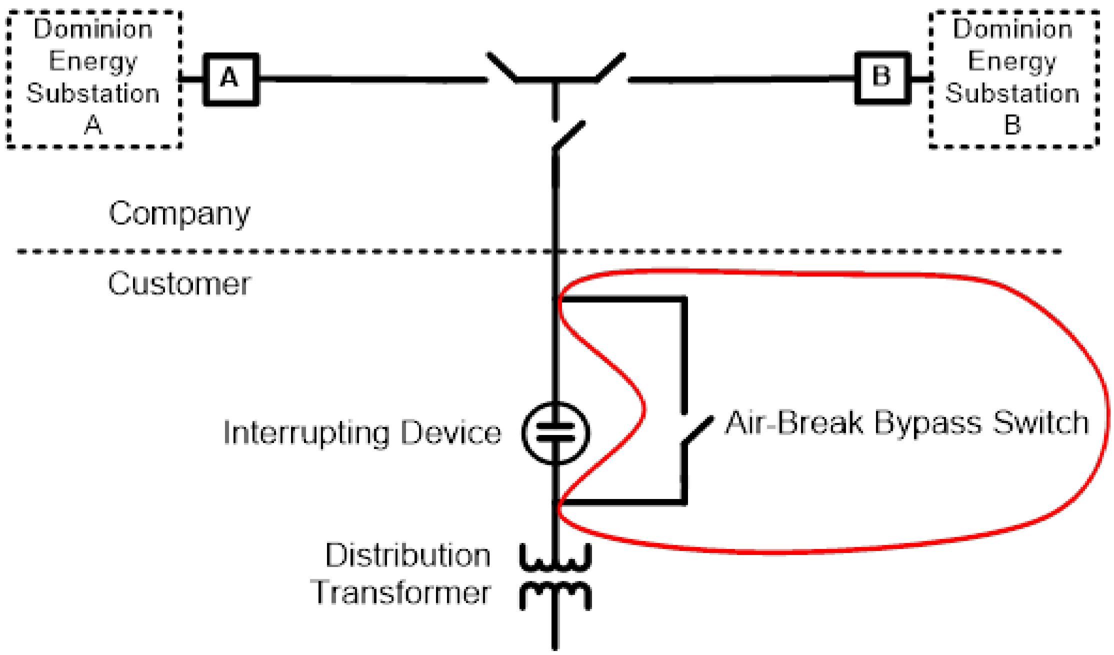
As an alternative to constructing a switching station at the tap point, the transmission line can be cut and looped in and out to a switching station located adjacent to the customer station as shown in Diagram 4.3.E. This arrangement can have its advantages since acquiring land and permitting a new station at the tap point would not be required. The customer should reserve property for construction of the DEV-ET owned Interconnection station.

A 4-breaker ring bus arrangement as shown in Diagram 4.3.E can generally be used to interconnect a proposed customer Facility of 100 MW and greater having two customer transformers, or to address a specific violation of the NERC standard outlined in Section C of Attachment 1- DEV-ET Planning Criterial. For cases in which there is only one customer transformer, a 3-breaker ring bus may be acceptable. With either arrangement, loss of line to the customer does not interrupt flow on the Transmission System and loss of a transmission line does not result in loss of service to the customer.

4.4 Prohibited Arrangements and Allowable Alternatives

DEV-ET does not allow by-pass switches around primary interrupting devices on the customer's distribution transformer at the point of Interconnection as shown in Diagram 4.4.A. DEV-ET's current system protection principles require that each system Element, (line, transformer, bus, etc.) always have primary relay protection in service when the Element is energized and placed in service. This ensures that all Elements have adequate protection for safe and reliable operation of the Transmission System and are ready to remove the Element from service should a fault occur. This is even more critical in cases like distribution tapped transformers where upstream line protection cannot provide backup coverage. The use of an air-break bypass switch would expose customer's personnel and equipment in an unprotected zone. This places risk to the BES' integrity as well as impacting all other customers served by the same transmission line.

Diagram 4.4.A: Prohibited by-pass switch



4.4.1 *Allowable Sample Alternatives*

A parallel circuit switcher arrangement as shown in Diagram 4.4.B provides a fully redundant capability. Another approach is the fused bypass as depicted in Diagram 4.4.C. The exact design, system protection configuration and operating arrangement may be customized as necessary, subject to review and approval by both DEV-ET and the Customer.

Diagram 4.4.B: Allowable sample alternative with interrupting devices

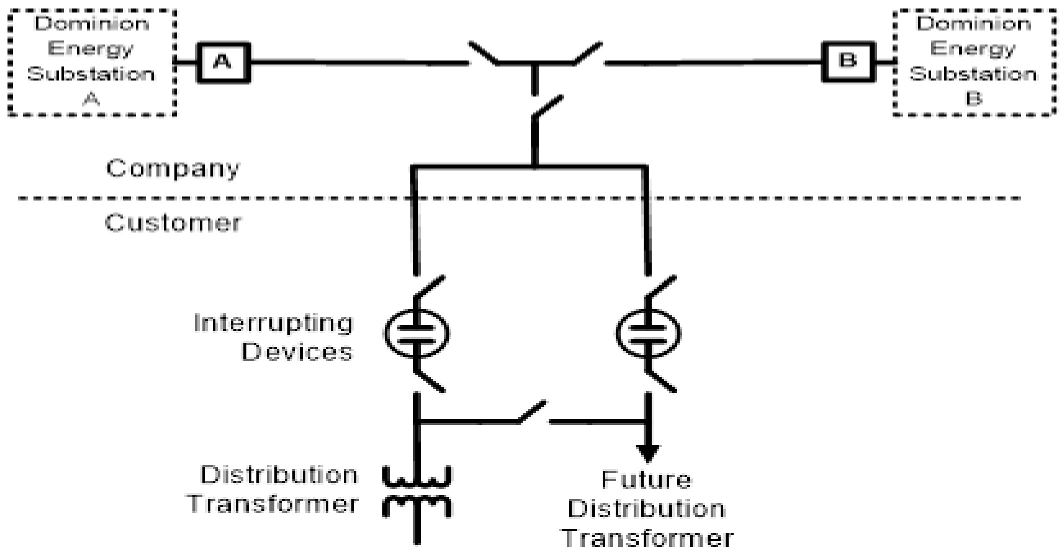
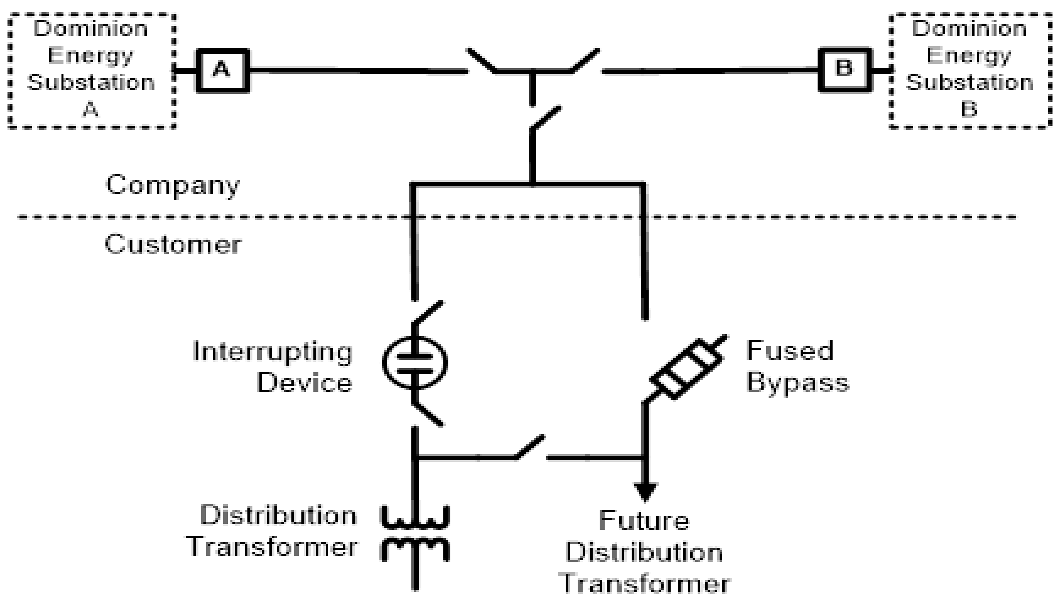


Diagram 4.4.C.: Allowable sample alternative with fused bypass



4.5 Tapping Company's Bus

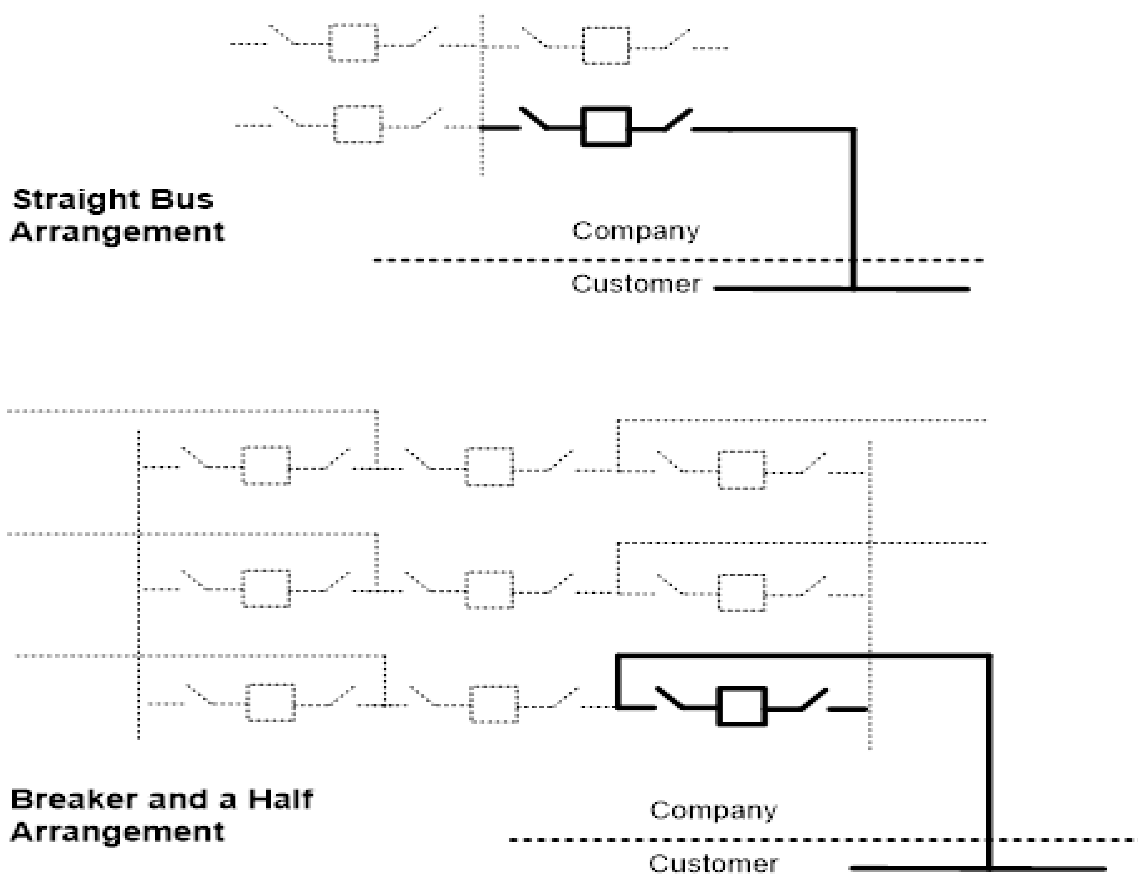
The requirements for direct interconnection to company's transmission bus is determined on case-by-case basis.

The following are preferred minimum load levels within the ten-year planning horizon for the direct interconnection of loads to the existing substation busses:

- 230 kV – 75 MW
- 138 kV – 50 MW
- 115 kV – 50 MW

In those cases where it may be practicable to tap an existing transmission substation bus to serve a customer, Diagram 4.5 indicates the typical Facilities arrangement for normal service:

Diagram 4.5: Tapping existing substation bus below 100 MW load



5.0 DEFINITIONS AND ACRONYMS

5.1 Definitions

Wherever used in this document with initial capitalization, the following terms are to have the meanings as specified below. Terms used in this document with initial capitalization not defined are to have the meanings specified in the PJM Open Access Transmission Tariff or NERC Glossary of Terms.

Capacity The seasonal maximum generating capability of the generation Interconnection Customer's Facility, measured in megawatts.

Distribution Facilities The Facilities rated at less than 69 kV which are owned and operated by the Company, and which are necessary to connect the Interconnection Customer's Facility to the Transmission System.

Emergency Condition(s) A condition or situation (i) that in the judgment of either party is imminently likely to endanger life or property; (ii) that in the sole judgment of The Company is imminently likely to affect adversely or impair the Transmission System or imminently will affect or impair the transmission systems of others to which the Transmission System is directly or indirectly connected; or (iii) that in the sole judgment of the generation Interconnection Customer is imminently likely to adversely affect or impair the Facility. Such a condition or situation includes, but is not limited to, overloading, or potential overloading of, excessive voltage drops, or other unusual operating conditions on the Transmission System or the generation Interconnection Customer's Facility such that the output of the Facility must be shut down or curtailed to avoid damaging the Facility or the Transmission System.

Good Utility Practice Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but intended to include acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority Any federal, state, local or other governmental, regulatory, or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, arbitrating body, or other governmental authority.

Interconnection Facilities All structures, equipment, devices, and apparatus owned or leased by, or under contract to each party presently in place or proposed to be installed, which are necessary to connect the Interconnection Customer's Facility(ies) to the DEV Transmission System.

Interconnection Customer A transmission, generation, or end user connected to, or seeking to connect to, the DEV Transmission System.

Interconnection Point The point at which the Facilities are physically connected to the Transmission System (including any Distribution Facilities required to facilitate the interconnection).

Metering Equipment All metering equipment currently installed at the Interconnection Customer's Facility and/or any other metering equipment to be installed at the metering points designated in the Interconnection Facilities, including Revenue Meters.

RTO A Regional Transmission Organization or any successor thereof which becomes responsible for operating the Company Transmission System to which the Interconnection Customer's Facility is connected. PJM Interconnection, L.L.C. is DEV's RTO.

Transmission Element Transmission Elements are primary equipment (69kV and above) that constitutes, or interconnects with, the DEV Electric Transmission System. Examples include buses, lines, or transformers with low side voltage 69kV or above, regardless of BES status.

Transmission System The Facilities owned by DEV that are used to provide transmission service, including any Distribution Facilities required to provide Wholesale Distribution Service, under the PJM Open Access Transmission Tariff (OATT).

Wholesale Distribution Service The provision of distribution service to wholesale customers, including generator Facilities, over Distribution Facilities as necessary to effectuate transmission service under the PJM OATT or Interconnection Service under this Agreement.

5.2 **Acronyms**

ANSI American National Standards Institute

IEEE Institute of Electrical and Electronic Engineers

NERC North American Electric Reliability Corporation

OATT PJM Open Access Transmission Tariff

PCC Point of Common Coupling

SERC Southeastern Electric Reliability Council

6.0 REVISION HISTORY

Revision Date	Revision #	Description	Revised By	Effective Date
08/24/1999	0.0	Original document created to meet the requirements of NERC Planning Standard I.C.S1.M1.	ET Planning staff	08/24/1999
05/01/2001	1.0	See Details for Revision 1.0 below	ET Planning staff	05/01/2001
09/07/2005	2.0	See Details for Revision 2.0 below	ET Planning staff	09/07/2005
05/29/2007	3.0	See Details for Revision 3.0 below	ET Planning staff	05/29/2007
12/22/2009	4.0	See Details for Revision 4.0 below	ET Planning staff	12/22/2009
12/22/2011	5.0	See Details for Revision 5.0 below	William F. Bigdely	12/22/2011
10/10/2012	6.0	See Details for Revision 6.0 below	William F. Bigdely	10/10/2012
11/22/2013	7.0	See Details for Revision 7.0 below	William F. Bigdely	11/25/2013
03/31/2014	8.0	See Details for Revision 8.0 below	William F. Bigdely	03/31/2014
07/16/2014	9.0	See Details for Revision 9.0 below	William F. Bigdely	07/18/2014
01/09/2015	10.0	See Details for Revision 10.0 below	William F. Bigdely	01/15/2015
03/26/2015	11.0	See Details for Revision 11.0 below	William F. Bigdely	03/27/2015
12/15/2015	12.0	See Details for Revision 12.0 below	William F. Bigdely	01/01/2016
05/15/2017	13.0	See Details for Revision 13.0 below	William F. Bigdely	06/01/2017
03/29/2018	14.0	See Details for Revision 14.0 below	William F. Bigdely	04/01/2018
12/13/2018	15.0	See Details for Revision 15.0 below	William F. Bigdely	01/01/2019
03/11/2019	16.0	See Details for Revision 16.0 below	William F. Bigdely	03/15/2019
03/11/2020	17.0	See Details for Revision 17.0 below	David Witt	04/01/2020
06/30/2020	18.0	See Details for Revision 18.0 below	David Witt	07/08/2020
02/22/2021	19.0	See Details for Revision 19.0 below	Hamidreza Sadeghian	04/01/2021
03/10/2022	20.0	See Details for Revision 20.0 below	Mark Gill	04/01/2022
02/16/2023	21.0	See Details for Revision 21.0 below	Amirreza Sahami	04/01/2023
11/15/2023	22.0	See Details for Revision 22.0 below	Aaron Winter	01/01/2024

Details for Revision 1.0

- Revised to include information regarding Dominion's generation interconnection procedures/process.

Details for Revision 2.0

- Revised to reflect transition from old NERC Planning Standards to NERC Reliability Standards, including changing the naming convention of all referenced standards throughout the document.

Details for Revision 3.0

Revised to reflect the following:

- Updates to NERC Reliability Standards
- Dominion's PJM Membership
- References to new SERC regional studies processes

Details for Revision 4.0

Revised to reflect the following:

- PJM Generation Queue Changes Section 4
- General Revisions all sections

Details for Revision 5.0

Revised the following:

- Section 2.12: Clarified content regarding synchronizing of Facilities.
- Exhibit A: Changed loading criteria to not exceed emergency rating of transmission Facility.
- Various errata changes.

Details for Revision 6.0

- Comprehensive overhaul to better align with the numerical flow of NERC Reliability Standard FAC-001.

Details for Revision 7.0

Revised to reflect the following:

- Annual review of Facility Connection Requirement document.
- Updated titles for approval process on page 1.
- Incorporated changes to reflect FERC approval of FAC-001-1 effective 11/25/2013.
- Section 3.1.5 – Removed "Coordination and Compatibility" and "Performance Tracking and Compliance"; Added "Protection System Misoperations".
- Section 3.1.13 – Added "Testing" paragraph
- Various errata changes.

Details for Revision 8.0

Revised Exhibit A – Transmission Planning Criteria R8 as listed below:

- Expanded description for Section G.1. TAPPING LINE BELOW 100 MW LOAD to emphasize the requirement of a fused bypass arrangement.

- Recreated diagrams throughout for consistency of style.

Details for Revision 9.0

Revised Exhibit A – Transmission Planning Criteria as listed below:

- Added Section C.2.8 – End of life criteria
- Reformatted headers to improve PDF navigation via bookmarks

Details for Revision 10.0

Revised Facility Connection Requirement document to reflect the following:

- Minor clarifications and annual review.
- Section 1 Purpose and Introduction: Added statement regarding applicability of document.
- Section 3.1.9 Voltage, Reactive Power, and power factor control; Generation Facilities subsection:
- Revised first bullet regarding generator control systems.
- Added new series of bullets regarding interconnected generation criteria.
- Revised Exhibit A – Transmission Planning Criteria (for details, see Revision History within Transmission Planning Criteria)

Details for Revision 11.0

- Revised Exhibit A – Transmission Planning Criteria (for details, see Revision History within Transmission Planning Criteria)

Details for Revision 12.0

- Made revisions to align with new version of the standard, FAC-001-2.
- Updated signature page to reflect personnel change.
- Relocated Section 3 content formerly associated with R3 in the prior version (FAC-001-1) to Section 3.3 Additional items per FAC-001 Application Guidelines and Technical Basis.
- Section 3.1 added bullet regarding distributed generation output for both conventional and alternative (solar, wind, etc.) sources
- Added sections 3.3.1 and 3.3.2 due to new information contained within Application Guidelines and Technical Basis of FAC-001-2.
- 3.3.5. Refined discussion of Protection System Design
- 3.3.6. Added reference to PJM Manual 01 – Control Center and Data Exchange Requirements
- Revised Exhibit A – Transmission Planning Criteria (for details, see Revision History within Transmission Planning Criteria)
- Integrated prior content from Transmission Planning Criteria, refined drawings, and associated discussions:
    - Section 5. TRANSMISSION LINE CONNECTIONS – GENERATION (previously Section F of Transmission Planning Criteria). Established minimum generation MW level for interconnection to the Transmission System.
    - Section 6. LOAD CRITERIA – END USER (previously Section G of Transmission Planning Criteria)

- Added Exhibit C DVP Electric Transmission Generator Interconnection Protection Requirements.
- Altered capitalization throughout the document to ensure consistent application of defined terms.

Details for Revision 13.0

- Performed annual review of document and exhibits.
- Updated approval page per personnel change since prior version.
- Revised references for new Dominion Energy corporate identity.
- Removed references to registration as an "LSE" (deactivated through NERC December 2015)
- Added Section 5.6 Interconnection Requirements for Distribution Connected Generation.
- Section 3.3.6. Metering and telecommunications, subsection "Revenue Metering Data Communications": added reference to Primestone billing data system.
- Revised Exhibit A – Dominion Energy Electric Transmission Planning Criteria (for details, see Revision History within Exhibit A)

Details for Revision 14.0

- Revised Exhibit A – Transmission Planning Criteria (for details, see Revision History within Transmission Planning Criteria)

Details for Revision 15.0

- Section 3.3: Added new section per new NERC FAC-001-3 standard; content within Section 3.3 of prior versions of this document is now in Section 3.4.
- Section 3.4.5 System protection and coordination (Protection system design) - added content re: Breaker Failure Protection.
- Section 5: Added reference to Exhibit C Protection Requirements; renumbered all sections and diagrams occurring after newly inserted section 5.3.
- Section 5.3: Added new section regarding generation connected to transmission tap lines.
- Section 8.1: Added definition for Transmission Element.
- Made all remaining revisions for Dominion Energy corporate identity, in text and in images (Rev 13 included initial related changes along with a clarifying statement in Section 1).
- Revised Exhibit C – Dominion Energy Electric Transmission Generator Interconnection Protection Requirements_Rev3 (for details, see Revision History within Exhibit C)

Details for Revision 16.0

- Revised Exhibit A – Transmission Planning Criteria (for details, see Revision History within Transmission Planning Criteria)

Details for Revision 17.0

- Performed annual review of document and exhibits.
- Updated approval page per personnel change since prior version.
- Section 1: Removed references to Section 3 for additional explanation.

- Section 3: Revised references to the FAC-001 R3 'Application Guidelines' to 'Supplemental Guidelines'.
- Section 3.2: Revised bullets for the subsequent changes list.
- Section 3.4.8: Revised reference and definition of 'insulation coordination'.
- Section 3.4.10: Updated IEC standard reference to 6100-4-15 and removed reference to UIE 96-10.
- Section 5: The Notes listed for Diagrams 5.1 and 5.2.B were updated to reference Section C of Exhibit A of this FAC-001 NCP.
- Revised Exhibit A – Transmission Planning Criteria (for details, see Revision History within Transmission Planning Criteria)

<u>Details for Revision 18.0</u>

- Revised Exhibit A – Transmission Planning Criteria (for details, see Revision History within Transmission Planning Criteria)

<u>Details for Revision 19.0</u>

- Updated signature page.
- Updated Purpose to match Purpose in NERC standard
- Updated Dominion Energy to Dominion Energy Virginia
- Various grammatical and formatting changes
- Section 3 – Moved section from number 7 to 3 and updated wording on applicability.
- Updated section and diagram numbers accordingly.
- Section 5.4.9 – Added the nighttime var requirements.
- Section 5.4.14 – Added reference to Attachment 4
- Revised naming of attached Exhibits to Attachments
- Revised Attachment 1 – Dominion Energy Virginia Electric Transmission Planning Criteria (for details, see Revision History within Transmission Planning Criteria)
- Revised Attachment 3 - Dominion Energy Virginia Generator Interconnection Protection Requirements (for details, see Revision History within Generator Interconnection Protection Requirements)
- Added Attachment 4 – Dominion Energy Virginia Bulk Power System Generator Ride-Through Requirements

<u>Details for Revision 20.0</u>

- Section 2 – Added references to PJM manuals
- Section 4.1.9 – Updated references to PJM manuals
- Updated signature page
- Updated formatting throughout the document
- Combined Sections 4, 5, 6, 7 from Revision 19.0 into Section 4.0 – Procedure in this Revision

<u>Details for Revision 21.0</u>

- Updated Signature Page
- Minor wording update
- Section 4.0, Compliance Requirement R3.3 – Reworded to clarify
- Section 4.1.6 – Added reference to Attachment 5
  Section 4.1.9 – Added reference to Attachment 5

- Updated Attachment 1, to reflect TPL001-5.1
- Attachment 5, Added new attachment

Details for Revision 21.0

- Updated Signature Page
- Reviewed and updated Requirement language where applicable for new version of Standard FAC-001-4
- Conducted Annual Review of the document and Attachments.

Dominion Energy Virginia
Electric Transmission Planning Criteria

Approved By Name and Title	Signature	Date Reviewed
Harrison Potter Manager Electric Transmission Planning & Strategic Initiatives		11/17/2023
Keith Graham Manager Electric Transmission Planning & Strategic Initiatives	Keith Graham	11/15/2023

Table of Contents

A. Scope and objective

The function of the transmission system is to transport power from generating resources to distribution systems to serve the demand of the end-user customers. Reliable transmission system operation implies maintaining continuity of service at sufficient voltage levels without overloading equipment under a wide range of operating conditions.

Virginia Electric and Power Company is commonly referred to as Dominion Energy Virginia (DEV). In this document, "DEV transmission system" refers to the transmission system owned by DEV. "Transmission system" refers to networked and radial facilities within the DEV system at voltage levels of 69, 115, 138, 230, and 500 kV. This document provides approved criteria upon which the needs for reinforcements and enhancements to the DEV transmission system are determined.

DEV's transmission planning criteria ensures adherence to the transmission planning standards of the North American Electric Reliability Corporation (NERC) and those of the SERC Reliability Corporation (SERC), one of the eight regional reliability organizations (RRO) of NERC. Unless noted, the Criteria in this document apply to generation, transmission, and end user facilities.

B. National and regional criteria and guides

B.1. NERC planning standards

The North American Electric Reliability Corporation was established to promote the reliability of the bulk electric systems of North America. NERC coordinates reliability standards for the power systems of the United States, the bordering provinces of Canada, and a portion of Mexico. NERC has developed planning standards to ensure the reliable operation of the interconnected bulk electric systems. These standards can be found at the NERC homepage.

The DEV Transmission Planning Criteria provides a description of how DEV performs simulated testing of the interconnected transmission system to determine its ability to withstand probable and extreme contingencies.

B.2. Regional reliability planning standards

NERC consists of eight regional reliability organizations. DEV is a member of the SERC Reliability Corporation (SERC), one of the eight regional reliability organizations of NERC. DEV plans the bulk electric system (BES) in coordination with PJM, its Transmission Planner (TP), to meet the requirements of NERC and SERC.

B.3. PJM planning standards

The DEV transmission system is integrated into planning and operations of the PJM Interconnections, L.L.C. RTO (PJM). PJM manages a regional planning process for generation and transmission expansion to ensure the continued reliability of the electric system. PJM annually develops a Regional Transmission Expansion Plan (RTEP) to meet system enhancement requirements for firm transmission service, load growth, interconnection requests and other system enhancement drivers. The criteria PJM uses in developing the RTEP is set forth in PJM Manual 14B – PJM Region Transmission Planning Process.

C. Transmission planning, steady-state criteria

C.1. Planning principles and standards

The transmission system must perform reliably for a wide range of conditions. Because system operators can exercise only limited direct control, it is essential that studies be made in advance to identify the facilities necessary to assure a reliable transmission system in future years.

The voltages and equipment loadings on the transmission system should be within acceptable limits, both during normal operation and for an appropriate range of potential system faults and equipment outages. The more probable contingency conditions should not result in voltages or equipment loadings beyond emergency limits. These ‘emergency limits’ can vary based on equipment type and allowable time period.

Tables 1A and 1B specify outage events that are analyzed by DEV at the forecasted load levels to determine if any thermal or voltage violations exist. Thermal capability is given with equipment ratings in amps or MVA. Voltage limits are in reference to the nominal design voltage. Adherence to the criteria given in these tables ensures that DEV’s transmission system meets the applicable reliability requirements of NERC, SERC, and PJM.

System readjustment is allowed when attempting to reduce line loadings or improve voltage profile (only as allowed by NERC Criteria). System readjustments considered in planning analysis include:

- Generation re-dispatch (excludes nuclear generation)
- Phase angle regulator adjustment[1]
- Load tap changer adjustment
- Capacitor bank switching
- Line switching
- Inductor switching
- Adjustment of Flexible AC Transmission System (FACTS) devices

Loadings on DEV transmission facilities over their normal rating, following a contingency, must be adjusted back down to normal rating within the time frame of the short-term emergency

[1] *For DEV, phase angle regulator adjustment is used to relieve loadings on the 115kV system in Yorktown and Chesapeake Energy areas. Phase shifting transformers control the division of real power among parallel paths. Chesapeake Energy Center and Yorktown Power Station have phase shifters between the 230 kV and 115 kV systems. The phase shifter transfers load from one voltage level to the other. Phase angle adjustment will be allowed within the parameters noted in PJM’s Manual 14B – PJM Region Transmission Planning Process (RTEP Reliability Planning section).*

rating. Any of the above listed system readjustments are allowable in this situation as DEV employs 8 hours short-term emergency ratings on transmission equipment, which allows sufficient time to implement any adjustments that reduce loadings to the normal rating.

Loadings on facilities over their short-term emergency ratings, following a contingency, must be adjusted back down to the short-term emergency rating within the 15-minute time frame of the load dump rating using the system readjustments listed above, which are only those readjustments that are feasible within 15-minutes by System Operators.

Dominion performs N-1-1 contingency analysis on transmission lines by taking a branch of a given line out of service as the first contingency. This mirrors real world conditions where after a fault takes an entire line out of service (breaker-to-breaker), branches of the line are restored through switching except for the branch that experienced the original fault. For the second contingency, breaker-to-breaker line outages are applied and analyzed.

If the criteria described in this document cannot be met, mitigation plans are developed. A valid mitigation plan will bring the system into compliance through the most judicious use of a variety of feasible options. These include the development of an operator action plan in conjunction with the use of short term ratings, generation re-dispatch, phase angle regulator adjustments, bus-tie switching, Remedial Action Schemes, or the installation of a physical reinforcement.

A Remedial Action Scheme (RAS), as interpreted from the NERC Reliability Standards Glossary of Terms, is designed to detect abnormal system conditions and take automatic corrective action to provide acceptable transmission system performance. The RAS isolates equipment other than faulted elements and/or reconfigures equipment outside of a zone containing faulted elements. A RAS may be applied as required to address thermal, voltage, or stability issues in accordance with NERC Transmission Planning (TPL) Standards and is subject to the RAS requirements of NERC Protection and Control (PRC) Standards 012 through 017. A RAS does not include automatic restoration to service of un-faulted elements within a faulted zone, under frequency and under voltage load shedding schemes, conventional generator out of step tripping schemes, or remote backup tripping schemes. DEV reviews all existing RASs periodically and adjusts settings as deemed necessary. DEV primarily installs RASs as a temporary measure until a more robust solution can be completed to provide acceptable system performance. Operating steps implemented as part of a Remedial Action Scheme shall be considered, provided that the failure of such system does not result in cascading outages or overloads.

In addition to those events and circumstances included in Tables 1A and 1B, Table 1C defines more severe but less probable scenarios that should also be considered for analysis to evaluate resulting consequences. As permitted in the NERC Planning Standards, judgment shall dictate whether and to what extent a mitigation plan would be appropriate.

Table 1A Steady-State Performance PLANNING Events and Dominion Energy CRITERIA

HIGH VOLTAGE (HV): 230 kV, 138 kV, 115 kV & 69kV Facilities

NERC TPL-001 Events (excludes DC)						Dominion Energy Criteria		
Category	**Initial Condition**	**Event[1]**	**Fault Type [2]**	**Interruption of Firm Transmission Service Allowed[4]**	**Non-Consequential Load Loss Allowed***	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
P0 No Contingency	Normal System	None	N/A	No	No	94% N	95%	105% & 103%
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	No[9]	No[12]	94% STE	93%	105% & 103%
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	No[9]	No[12]	94% STE	93%	105% & 103%
		2. Bus Section Fault	SLG	Yes	Yes	100% STE	90%	105% & 103%
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	Yes	Yes	100% STE	90%	105% & 103%
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	Yes	Yes	100% STE	90%	105% & 103%
P3 Multiple Contingency [see Dom Energy Note "A", "B" & C]	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	No[9]	No[12]	94% STE	93%	105% & 103%
P4 Multiple Contingency *(Fault plus stuck breaker[10])* [see Dominion Energy Note "B"]	Normal System	Loss of multiple elements caused by a stuck breaker[10] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	Yes	Yes	100% STE	90%	105% & 103%
P5 Multiple Contingency *(Fault plus relay failure to operate)* [see Dominion Energy Note "B"]	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection Sytem[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	Yes	Yes	100% STE	90%	105% & 103%

Table 1A continued on next page

Table 1A Steady-State Performance PLANNING Events and Dominion Energy CRITERIA *(continued)*

HIGH VOLTAGE (HV): 230 kV, 138 kV, 115 kV & 69kV Facilities

NERC TPL-001 Events (excludes DC)						Dominion Energy Criteria		
Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Interruption of Firm Transmission Service Allowed[4]**	**Non-Consequential Load Loss Allowed***	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
P6 Multiple Contingency *(Two overlapping singles)* [see Dominion Energy Note "B" & C]	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6]	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	Yes	Yes	100% STE	90%	105% & 103%
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of any two adjacent (vertically or horizontally) circuits on common structure[11]	SLG	Yes	Yes	100% STE	90%	105% & 103%

<u>Dominion Energy Notes for Table 1A</u>

See separate listing *Table 1 (A & B) Footnotes* for superscript numbered footnotes.

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Note "A" - See *Section C.2.1.3 – Critical stress case development and studies* for details.

Note "B" - Areas of the system that become radial post-contingency will be included for monitoring of thermal and voltage violations for all load levels served by the radial.
Note "C" – System adjustment should be performed after first contingency event (Initial Condition).

* If the aggregated consequential or non-consequential load loss exceeds 300 MW, system reinforcements will be required.

** Percent of Nominal Voltage (Note: Voltage limits for North Anna and Surry Power Stations are governed by the requirements of their respective Nuclear Plant Interface Requirements (NPIR) with Dominion Energy Electric Transmission as noted in Section E.3). A lower overvoltage limit of 103% is applied to 138KV facilities based on the age and number of legacy switches on the network at this voltage.

N – Normal Rating

STE – Short Term Emergency

LD – Load Dump

Table 1B Steady-State Performance PLANNING Events and Dominion Energy CRITERIA

EXTRA HIGH VOLTAGE (EHV): 500kV Facilities

NERC TPL-001 Events (excludes DC)						Dominion Energy Criteria		
NERC Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Interruption of Firm Transmission Service Allowed[4]**	**Non-Consequential Load Loss Allowed***	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
P0 No Contingency	Normal System	None	N/A	No	No	94% N	102.5%	108%
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	No[9]	No[12]	94% STE	101%	109.6%
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	No[9]	No[12]	94% STE	101%	109.6%
		2. Bus Section Fault	SLG	No[9]	No	100% STE	100%	109.6%
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	No[9]	No	100% STE	100%	109.6%
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	Yes	Yes	100% STE	100%	109.6%
P3 Multiple Contingency [see Dominion Energy Note "D", "E" & "F"]	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	No[9]	No[12]	94% STE	101%	109.6%
P4 Multiple Contingency *(Fault plus stuck breaker[10])* [see Dominion Energy Note "D"]	Normal System	Loss of multiple elements caused by a stuck breaker[10] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	No[9]	No	100% STE	100%	109.6%
P5 Multiple Contingency *(Fault plus relay failure to operate)* [see Dominion Energy Note "D"]	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	No[9]	No	100% STE	100%	109.6%

Table 1B continued on next page

Table 1B Steady-State Performance PLANNING Events and Dominion Energy CRITERIA *(continued)*

EXTRA HIGH VOLTAGE (EHV): 500kV Facilities

NERC TPL-001 Events (excludes DC)						Dominion Energy Criteria		
NERC Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Interruption of Firm Transmission Service Allowed[4]**	**Non-Consequential Load Loss Allowed***	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
P6 Multiple Contingency *(Two overlapping singles)* [see Dominion Energy Note "D" & "F"]	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6]	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	Yes	Yes	100% STE	100%	109.6%
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of any two adjacent (vertically or horizontally) circuits on common structure[11]	SLG	Yes	Yes	100% STE	100%	109.6%

Dominion Energy Notes for Table 1B

See separate listing *Table 1 (A & B) Footnotes* for superscript numbered footnotes.

Note "D" - See *Section C.2.1.3 – Critical stress case development and studies* for details.

Note "E" - Areas of the system that become radial post-contingency will be included for monitoring of thermal and voltage violations for all load levels served by the radial.

Note "F" – System adjustments should be performed after first contingency event (Initial Condition).

* If the aggregated consequential or non-consequential load loss exceeds 300 MW, system reinforcements will be required.

** Percent of Nominal Voltage (Note: Voltage limits for North Anna and Surry Power Stations are governed by the requirements of their respective Nuclear Plant Interface Requirements (NPIR) with Dominion Energy Electric Transmission as noted in Section E.3).

N – Normal Rating

STE – Short Term Emergency

LD – Load Dump

Table 1C Steady-State Performance EXTREME Events and Dominion Energy CRITERIA

NERC TPL-001 Events (excludes DC)					Dominion Energy Criteria		
Category	**Event Note "G"**		**Interruption of Firm Transmission Service Allowed**	**Non-Consequential Load Loss Allowed**	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
N-2 Two Contingencies	Loss of a single generator, Transmission Circuit, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, shunt device, or transformer forced out of service <u>prior to System adjustments.</u>		YES	YES	100% LD	90%	Note "M"
LAE Local Area Events	Local area events affecting the Transmission System such as:	a. Loss of a tower line with three or more circuits.[11]	YES	YES	100% LD Note "H"	90%	Note "M"
		b. Loss of all Transmission lines on a common Right-of-Way[11].	YES	YES	100% LD Note "I"	90%	Note "M"
		c. Loss of a switching station or substation (loss of one voltage level plus transformers).	YES	YES	100% LD Note "J"	90%	Note "M"
		d. Loss of all generating units at a generating station.	YES	YES	100% LD Note "K"	90%	Note "M"
		e. Loss of a large Load or major Load center.	YES	YES	100% LD Note "L"	90%	Note "M"
WAE Wide Area Events	Wide area events affecting the Transmission System based on System topology such as:	a. Loss of two generating stations resulting from conditions such as: i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.	YES	YES	100% LD for both HV and EHV		Note "M"
		b. Other events based upon operating experience that may result in wide area disturbances.	YES	YES			Note "M"

** Percent of Nominal Voltage (Note: Voltage limits for North Anna and Surry Power Stations are governed by the requirements of their respective Nuclear Plant Interface Requirements (NPIR) with Dominion Energy Electric Transmission as noted in Section E.3).
N – Normal Rating, STE – Short Term Emergency, LD – Load Dump

Dominion Energy Notes for Table 1C

See separate listing *Table 1 (A, B & C) Footnotes* for superscript numbered footnotes.

Note “G” – For all extreme events evaluated:

- Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
- Simulate Normal Clearing unless otherwise specified.

Note “H” – The loss of three or more transmission circuits on a common structure should not result in cascading outages beyond the load area immediately involved. The overall supply system to a major load area should be able to withstand the loss of all circuits on a common structure and still supply most of the load in the area with tolerable voltage (at least 90% of nominal). A major load area would be an area similar to the Norfolk/Virginia Beach area or the Northern Virginia area.

Note “I” – The loss of transmission circuits on a common right of way should not result in cascading outages beyond the load area immediately involved. The overall supply system to a major load area should be able to withstand the loss of all circuits on a common right of way and still supply most of the load in the area with tolerable voltage (at least 90% of nominal). A major load area would be an area similar to the Norfolk/Virginia Beach area or the Northern Virginia area.

Note “J” – The loss of a switching station or substation (one voltage level plus transformers) should not result in cascading outages or intolerably low voltages (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than its load dump rating during the period required to make prompt power supply adjustments to reduce overloads to less than its emergency rating (STE). The consequential load due to the loss in the affected station is not to exceed 300 MW.

Note “K” – The loss of all generation at a generating station should not result in cascading outages or intolerably low voltages (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than its load dump rating during the period required to make prompt power supply adjustments to reduce overloads to less than its emergency rating (STE).

Note “L” – The loss of a large load or major load center should not result in cascading outages or intolerably low voltages (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than its load dump rating during the period required to make prompt power supply adjustments to reduce overloads to less than its emergency rating (STE).

Note “M” - High Voltage (HV): 105%; Extra High Voltage (EHV): 109.6%

Table 1 (A, B & C) Footnotes [NERC Standard TPL-001-4]

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage apply to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. For purposes of this standard, non-redundant component of a Protection System to consider are as follows:
    a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;
    b. A single communications system associated with protective functions necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communication system that is both monitored and reported at a Control Center;
    c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit);
    d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

C.1.1. Voltage limits at generating stations

Plant auxiliary power equipment requires adequate voltages in order to maintain reliable operation of online generators as well as to provide for reliable startup capability for offline generators. Minimum transmission voltage limits specific to generating stations, are used to ensure plant auxiliary equipment is provided with adequate voltages during both online and offline operation. These limits apply to all classes of generation except wind turbines, for which the system transmission voltage limits are adequate.

In cases where plant auxiliary power is supplied by power transformers not equipped with a load tap changer (LTC) or equivalent voltage control device, the voltage limits at the low side of the Generator Step-up Unit (GSU) are established as 0.95 per unit (minimum) and 1.05 per unit (maximum) unless otherwise specified by the generator owner.

C.2. Detailed steady-state criteria

C.2.1. System load level

C.2.1.1. Peak period studies

The peak load period must be studied to determine future requirements for the transmission system. The basic references for system peak load to be used in studies for future years are the total corporate system load projection provided by the PJM Load Analysis. The actual peak load in any given future year is likely to be higher or lower than the forecast value. A ‘50/50’ forecast provides a peak load projection with a 50% probability that the actual peak will be higher than the level forecasted in that year.

C.2.1.2. Off-peak period studies

Studies should also be conducted for the purpose of determining risks and consequences at light load or shoulder peak conditions, and for any other period for which system adequacy cannot be evaluated from peak period study results. For these off-peak periods, it is assumed that the number of hours of occurrence is substantially higher than the number of hours at or near peak load levels. In addition, severe drought conditions effecting hydro generation plant availability and its impact on the transmission system are also studied.

C.2.1.3. Critical stress case development and studies

DEV studies the transmission system under both normal and critical system stress conditions. For NERC Category P3 Analysis, DEV will outage the most critical generator in the area being studied, and the resulting power flow case is considered a critical stress case. Under this critical stress case condition, the generator being studied is taken off-line and the remaining generators connected to the DEV System are proportionally increased to make-up for the lost generation. If there are not enough generation resources available within the DEV system, or the use of DEV generation resources would not provide an adequate base case, then PJM generation resources should be utilized to make-up any generation deficiency. This resulting critical stress case is then analyzed for NERC Compliance based on the transmission contingency events listed in Table 1A and Table 1B Category P3(Multiple Contingency).

C.2.2. Power transfers

All studies should consider known firm power transfers affecting the DEV transmission system. This includes known firm transmission service reservations, including those with rollover rights, as well as parallel path power transfers through the system that may impact system reliability.

DEV is part of a larger regional power system that must be capable of withstanding certain levels of power transfers between or through sub areas of the region. PJM conducts load and generator deliverability tests for specific sub areas as part of the Regional Transmission Expansion Plan (RTEP) process to determine whether the system can accommodate these transfers. The DEV transmission system must meet this transfer Load and Generator Deliverability Requirement. A description of the deliverability testing procedures can be found in PJM Manual 14B – PJM Region Transmission Planning Process[2]. SERC Reliability Corporation also performs transfer limit testing to trend the strength of the transmission system. The results of these studies may also indicate a need to increase transfer strength on the DEV system.

DEV routinely tests the capability of the transmission system to transfer reasonable amounts of power (approximately 2000 MW) in excess of firm purchases, sales and transfers, between and among the Company and the neighboring utilities. Such tests are conducted under two basic scenarios: (1) with all transmission facilities in service at or below the maximum continuous normal rating; and (2) with one transmission circuit or transformer out of service while maintaining the loading on all remaining transmission facilities at or below the maximum continuous emergency rating. Any new facilities connected to the transmission system shall not significantly decrement, the First Contingency Incremental Transfer Capability (FCITC) for transfers between utilities. A FCITC decrement in excess of 5% will be considered significant in most cases.

[2] Based on DEV criteria for Generation Deliverability, the thermal thresholds for Single contingencies (NERC P1 category) and Non-Single contingencies (NERC P2, P4, and P7 categories) are 94% of Short Term Emergency (STE) and 100% of Load Dump (LD), respectively.

C.2.3. Equipment ratings

Allowable loadings for transmission facilities are maintained by DEV in an equipment ratings database. In most cases, equipment is given at least a normal rating and one emergency rating. Some equipment is given multiple emergency ratings. These ratings differ by allowable duration, and are referred to as short-term, long-term, and load dump.

The specific procedure used for determining equipment ratings is outlined in the DEV Transmission Facility Ratings Methodology technical reference document.

C.2.4. Circuit breaker interrupting capability

All Facilities must equal or exceed the fault duty capability necessary to meet system short circuit requirements as determined through short circuit analyses, and shall fully comply with the latest ANSI/IEEE C37 standards for circuit breakers, switch gear, substations, and fuses.

Under normal conditions, the current through a circuit breaker shall not exceed the maximum continuous ratings of that breaker. Further, a circuit breaker shall have sufficient capability to interrupt a close-in single phase fault or three phase-to-ground fault.

C.2.5. Reactive power planning

The objective of system reactive power planning is to efficiently coordinate the reactive requirements of the transmission and distribution systems to satisfy voltage criteria. Meeting this objective ensures voltage stability, provides generator auxiliary power systems on the distribution system with adequate voltage, and minimizes transmission losses and reactive interchange. System reactive requirements can be controlled by changing generation excitation, operating synchronous condensers, changing transformer tap positions, switching transmission and distribution level static capacitors, switching shunt reactors, and adjusting solid-state reactive compensation devices (SVCs, etc.).

The DEV system is planned so that transmission voltages will be maintained within an acceptable range for normal and emergency conditions as described in Tables 1A and 1B.

Low transmission voltage will lead to undesirable effects in both the transmission and distribution systems, such as higher losses, reduced insulation life, and reduced effectiveness of capacitors. These effects would also increase the difficulty in recovering from low transmission voltage situations. The outage events analyzed to assess voltage adequacy are the same as those listed in Tables 1A and 1B. Distribution facilities which are maintaining power factors at the Transmission Point of Interconnection (POI) that are less than PJM's requirement (per Manual 14B – PJM Region Transmission Planning Process) and DEV's requirement (97.3% lagging) may not be able to maintain satisfactory voltage to customers served from these distribution facilities when transmission system voltages are at or near the lower voltage limits of normal and emergency transmission system operations.

Conversely, high transmission voltages that exceed operating voltage schedules can stress generation, distribution, and transmission equipment and lead to premature fatigue or even failure.

C.2.6. Radial transmission lines

A Radial transmission line is defined as a single line that has one transmission source, serves load, and does NOT tie to any other transmission source (line or substation). Unlike load served from a network transmission line having two sources where a downed conductor or structure can be sectionalized for load to be served before repairs are completed, load served from a single source radial transmission line cannot be reenergized until all repairs to the line are completed. Accordingly, loading on single source radial transmission lines will generally be limited to the following:

- 100 MW Maximum
- 700 MW-Mile Exposure (MW-Mile = Peak MW X Radial Line Length)

A factor in evaluating the load limitation on a radial transmission line is the degree to which the distribution load can be switched to circuits served from other sources and whether such capability can be reasonably added. Other factors include the ability to perform maintenance on the radial transmission line, the outage history of the radial transmission line, load density and type, tie capability, etc.

Once a radial loading limit exceeds any of these thresholds, an additional transmission source may be required. Acceptable transmission sources include but are not limited to the following:

- Network from a separate transmission substation source (Preferred)
- Loop back to same transmission substation source
- Normally open network or loop transmission source

C.2.7. Network transmission lines – Limitations on direct-connect loads

A network transmission line is defined as one that connects two network transmission sources (connect to other lines & substations) and a "Tap point" is defined as a direct connection of a customer to a network transmission line without addition of any transmission breaker or breakers to split the line. Network transmission lines facilitate network flows and could serve directly connected (Tapped) loads. In the Dominion Energy system, 500, 230, 138, 115 and 69kV lines are considered transmission, and all with the exception of 500kV could be tapped to serve customer load.

In general, the number of direct-connect loads (tapped facilities) should be limited to four (4); however, Good Utility Practice and sound engineering judgment must be exercised in application of this criteria.

C.2.8. Substation – Limitation on direct-connect loads

The amount of direct-connect load at any substation will be limited to 300MW.

C.2.9. End of life criteria

Electric transmission infrastructure reaches its end of life as a result of many factors. Some factors such as extreme weather and environmental conditions can *shorten* infrastructure life, while others such as maintenance activities can *lengthen* its life. Once end of life is recognized, in order to ensure continued reliability of the transmission grid, a decision must be made regarding the best way to address this end-of-life asset.

For this criterion, "end of life" is defined as the point at which infrastructure is at risk of failure, and continued maintenance and/or refurbishment of the infrastructure is no longer a valid option to extend the life of the facilities consistent with Good Utility Practice and Dominion Energy Transmission Planning Criteria. The infrastructure to be evaluated under this end-of-life criteria are all regional transmission lines operated at 500 kV and above.

The decision point of this criterion is based on satisfying two metrics:

1) *Facility is nearing, or has already passed, its end of life, and*
2) *Continued operation risks negatively impacting reliability of the transmission system.*

For facilities that satisfy both of these metrics, this criterion mandates either replacing these facilities with in-kind infrastructure that meets current Dominion Energy standards or employing an alternative solution to ensure the Dominion Energy transmission system satisfies all applicable reliability criteria.

Dominion Energy will determine whether the two metrics are satisfied based on the following assessment:

1. End of Life

Factors that support a determination that a facility has reached its end of life include, but are not limited to,

- **Condition** of the facility, taking into consideration:
    - Industry recommendations on service life for the particular type of facility
    - The facility's performance history
        - Documented evidence indicating that the facility has reached the end of its useful service life
    - The facility's maintenance and expense history
- **Third-party assessment -** While not required, Dominion Energy has the option of seeking a third-party assessment of a facility to determine if industry specialists agree the facility has reached the end of its useful service life

2. Reliability and System Impact

The reliability impact of continued operation of a facility will be determined based on a planning assessment and operational performance considerations. The end-of-life determination for a facility to be tested for reliability impact will be assessed by evaluating the impact on short term and long term reliability with and without the facility in service. The existing system with the facility removed will become the base case system for which all reliability tests will be performed.

The primary four (4) reliability tests to be considered are:

1. NERC Reliability Standards
2. PJM Planning Criteria – As documented in PJM Manual 14B – PJM Region Transmission Planning Process
3. Dominion Energy Transmission Planning Criteria contained in this document
4. Operational Performance – This test will be based on input from PJM and/or Dominion Energy System Operations as to the impact on reliably operating the system without the facility

Additional factors to be evaluated under system impact may include but not be limited to:

1. Market efficiency
2. Stage 1A ARR sufficiency
3. Public policy

4. SERC reliability criteria

Failure of any of these reliability tests, along with the end-of-life assessment discussed herein, will indicate a violation of the End-of-Life Criteria and necessitate replacement as mandated earlier in this document.

After the end of service life and reliability impact of a facility are evaluated and it has been determined that the facility violates the End-of-Life Criteria, a determination will be made as to whether replacement of the facility is the most effective solution for an identified reliability need, or whether an alternative solution should be employed. One or more of the following factors may be considered in determining whether to proceed with facility replacement or with an alternative solution:

- Planning analysis which may include power flow studies
- Operational performance
- System Reliability
- Effectiveness of the alternative as compared to the replacement facility
- Future load growth in the study area
- Future transmission projects or interconnects that impact the study area
- Constructability comparison
- Cost comparison

C.3. Selection of generation dispatch used in DEV Power Flow Studies

The PJM RTEP Power Flow case for the year under study is the starting point for DEV Power Flow Studies. The generation dispatch in the PJM RTEP case is developed based on PJM's Study Methodologies as outlined in PJM's Manual 14B. DEV may modify this generation dispatch to develop a Base Power Flow case which is used as the starting point of DEV's Analysis to support PJM's RTEP Study Process. These modifications may include the following:

- Generating Units which have significant environmental limitations which severely limit the units availability in real time operation may be modeled as being off-line.
- Generating Units which have been identified in DEV's IRP Filings in Virginia/North Carolina as being "Potential" Generation Retirements may be modeled as being off-line.
- Known outages of a generating unit which are consistent with NERC TPL-001 selection criteria may be modeled as being off-line.

The base power flow dispatch provided to DEV in a power flow case which is used to analyze the reliability impact (Feasibility Study/System Impact Study) of generators in the PJM Generation Queue is typically modified by DEV. Since the case provided to DEV typically has all queue generation located on the DEV System as being off-line, DEV will modify the generation dispatch for power flow studies. Specifically, will turn on all higher order queue generators then the queue request under study as the base case condition for the generator under study. To account for this additional generation, generators located on the PJM System are proportional re-dispatched to account for this additional generation.

D. Transmission planning, system stability criteria

D.1. Introduction

There are many variables that affect the results of a stability study. These factors include but are not limited to:

- pre-fault and post-fault system configurations
- system load level and load characteristics
- generation dispatch patterns, unit dynamic characteristics and proximity to other generating units types and locations of system disturbances
- fault clearing time(s)
- the amount of flow interrupted as a result of switching out faulted elements
- level of detail and accuracy of available models/data

Many of these factors change in the operating area on a continuous basis. Every effort should be made to evaluate the most severe, yet credible/probable stability study scenarios in the planning area.

D.2. General criteria

Since 2005, PJM becomes the Transmission Planner (TP) for DEV. PJM conducts stability studies to ensure that the planned system can withstand NERC criteria disturbances and maintain stable operation throughout the PJM planning horizon, as well as the DEV's specific stability practices in ET Planning Criteria. Such stability analyses include but are not limited to:

- System impact stability study for Bulk Electric System[3] (BES) generation interconnection queue projects prior the in-service date of the projects
- Periodical Baseline, N-1-1 stability study for individual BES generation stations in

[3] NERC Bulk Electric System Definition Reference Document, link: https://www.nerc.com/pa/Stand/2018%20Bulk%20Electric%20System%20Definition%20Reference/BES_Reference_Doc_08_08_2018_Clean_for_Posting.pdf

compliance with the NERC TPL-001 standard

- Periodical Baseline, N-1-1 stability study for selected area using dynamic load model for voltage stability purpose in compliance with the NERC TPL-001 standard
- Periodical extreme events dynamic study for selected area for voltage stability purpose in compliance with the NERC TPL-001 standard
- Under frequency load shedding (UFLS) study for selected area periodically in compliance with the NERC and SERC PRC-006 standards

DEV ET Planning team supports PJM on their stability analysis responsibilities and conducts internal stability analyses. Stability study activities performed by ET Planning include but are not limited to:

- Assisting and reviewing PJM's system impact stability study for BES generation interconnection queue projects.

  Stability analysis is not required for units that are not part of the BES as defined by NERC. In PJM practice, generators rated 20 MVA or less in size and with aggregate plant capacity less than or equal to 75 MVA are not required to be studied in the system impact stability study process. DEV ET Planning determines whether to conduct the stability study for these units.
- Assisting, reviewing, and supporting PJM's stability study in compliance with the NERC TPL-001 standard
- Delayed protective relay tripping system stability analysis per the requests from DEV ET System Protection group
- Stability studies required in PJM Regional Transmission Expansion Plan (RTEP) projects (include but are not limited to projects involving FACTS devices)
- The substation physical security stability analyses in compliance with the NERC CIP-014 standard
- Special stability studies required by long-term (above 5 years) strategic planning projects

D.3. Study horizon

Stability studies performed for the near-term horizon (1-5 years) include but not limited to following types and can be implemented in a relatively short period of time:

- Transmission protection enhancement
- Generation protection enhancement
- Generation equipment enhancement
- Apply/modify/remove Remedial Action Scheme (RAS)
- Install/modify FACTS devices

- Establish operating restrictions for a contingency period covering forced or maintenance outages

For identified stability problems that cannot be remedied with the aforementioned solutions, new transmission infrastructure may be required to ensure stability for safe and reliable operation of the electric grid. In cases where a near-term horizon stability study indicates a potential correction that may require much longer lead time, a stability study for longer term would then be performed.

Stability studies performed for the long-term horizon (above 5 years) are determined by specific long-term strategic planning projects. The scope of the long-term studies is to better understand the grid performance of the DEV transmission system in a longer time scale and prepare for challenges with the rapidly changing generation and load environment and from the adoption of new technologies. Study results of such scenarios are carefully analyzed and the findings provide important supplemental information to the development of DEV's transmission expansion plan.

D.4. Dynamics data collection

PJM will collect dynamic data and submit to Multi-Regional Modeling Working Group (MMWG) as outlined in the Eastern Interconnection Reliability Assessment Group (ERAG) MMWG Procedural Manual.

Dominion Energy Electric Transmission Planning is responsible for submitting dynamic data to PJM for Transmission Owner equipment with dynamic characteristics (e.g. FACTS devices) and dynamic loads data.

D.5. Stability study case development

Planning area studies for stability analysis are performed using estimated snap-shots of the expected system operating conditions for the study period selected. The power flow base cases that match dynamics data for the Eastern Interconnection are prepared by the Multi-regional Modeling Working Group (MMWG) for selected years on an annual basis.

For individual stability analysis, the analysis performer is responsible to work with DEV ET Planning modeling team to develop most appropriate load flow and dynamic cases for the study. Such model development activities may include:

- Adjustment to the model topology to include transmission/generation projects completed before the targeting study date
- Adjustment to area loads and generation re-dispatch schemes to match the targeting study scenario
- Adjustment to dynamic model parameters and other system assumptions per the specific study scope

After the dynamics model setup, an unperturbed dynamic simulation for 20 -30 seconds is required to ensure that the steady-state stability is maintained.

D.6. Selection of generation dispatch

The economic dispatch used in internal power flow base cases may not represent conditions which could pose a stability risk. Therefore, the power flow cases may be stressed to test the area or generation under study. For example, increased transfers near generating facilities can have an adverse impact on transient stability and therefore need to be accounted for when creating stressed yet credible system dispatches for the stability studies.

Unit dispatch for transient stability studies also differs from the conventional power flow analysis. Units in the study region are generally dispatched to maximum real power output (Pmax), and at leading power factor at the low side of the GSU provided that the equipment voltage limits are not violated. Specifically, units under study and electrically close that fall within the study region[4] should be dispatched to absorb approximately 50% of the minimum reactive capability (Qmin) without violating the terminal voltage limits (generally 0.95 pu).

D.7. Selection of contingencies

Contingency categories and simulation specifications are based on Table 1 of NERC Reliability Standard TPL-001.

For generation interconnection system impact study and TPL-001 compliance stability study, DEV ET Planning adopts the same contingency criteria and margins as used in PJM stability study.[5] For other stability analyses initiated by ET Planning, the analysis performer is responsible to select the most appropriate contingency criteria and margins.

D.8. What to look for in study results

Checks are performed to make sure all on-line units initialize properly without any error messages.

Checks are performed to make sure the system is stable within the acceptable operating criteria:

- Acceptable Transient Voltage Recovery: When a fault occurs on the transmission system, system voltages are temporarily reduced. Once the fault is cleared, voltages follow transient voltage recovery trajectories governed by system dynamics. Regardless of the load model that is selected, the voltage following fault clearing shall recover to a minimum of 0.7 p.u. after 2.5 seconds. The transient voltage recovery criteria should be satisfied at BES buses.
- Acceptable Damping: Following the disturbance, the oscillations of the monitored parameters display positive damping. The damping ratio should reach 3% or better for

[4] Engineering judgment must be applied in selecting the generators that *electrically close* to unit(s) under study.

[5] PJM Manual 14B: PJM Region Transmission Planning Process Attachment G: PJM Stability, Short Circuit and Special RTEP Practices and Procedures

inter-area oscillations and 4% or better for local mode oscillations.

Solutions identified in section D3 are considered for situations where transient voltage or oscillation damping is not met, or if transient stability is not maintained. If the inter-area oscillations have an unacceptable damping ratio and other entities' units are found to be participating significantly, then it may require a joint study between the affected parties. N-1-1 contingencies with no re-dispatch are considered to ensure transient stability is maintained with positive damping. If the oscillation damping is positive but does not meet the criteria above, operation restriction may be applied to ensure sufficient oscillation damping for both local and inter-area modes of oscillations.

For system conditions and selected contingencies that results in generator transient instability, additional analysis is performed to quantify the risk of cascading events and potential for blackout conditions. Cascading failure analysis will consider a risk-based study of the loss of the generating unit based on expected protection and control as well as unexpected tripping. Depending on the size and expanse of the affected area, other solution options, operating restrictions, or transmission investments may be considered.

Since the transmission planning studies are performed for an estimated operating condition for a future date, the post disturbance thermal loading and voltage levels may vary widely when real disturbance occurs. This is because the load, generation dispatch and available reactive resources in real time may be quite different than the ones studied in planning area. For this reason, the thermal limits and voltage conditions should be checked using the real-time contingency analysis tool.

D.9. Implementation procedure

Stability analysis may warrant corrections or additional requirements in order to meet the stability criteria listed in this document. The implementation procedure for such items depends on the type of corrections warranted and the nature of installation. The following is a general guideline for Transmission Planning to get such fixes implemented.

D.9.1. For existing installations

- Corrections related to transmission fault clearing times near generating stations that can be resolved by changes to existing relay set points shall be communicated to DEV ET System Protection group for implementation. PJM should also be informed as to the results of this analysis.
- A Capital project shall be generated for corrections related to transmission fault clearing times near generation stations that require baseline improvements such as new or additional equipment. All Capital projects shall first be validated, approved and assigned cost and construction responsibility by the PJM Regional Transmission Expansion Planning (RTEP) process.
- Output restrictions and/or unit trip(s) for the next pending contingency

condition identified by DEV in routine planning studies, will be communicated to the SOC. In turn, the SOC shall inform PJM for implementation as appropriate.

- In case of scheduled maintenance or construction outages, the results/recommendations shall be conveyed to the person through whom the stability analysis request came to the stability engineers. For example, if a Project Manager requests such analysis to the load Planning Engineer, the stability engineer shall forward his analysis to the load Planning Engineer. If SOC requests such analysis, the results/recommendations shall be forwarded to SOC which in turn shall inform PJM for implementation as appropriate.

D.9.2. For new installations or capacity additions

New generating resources are studied as part of the PJM Generation Interconnection Queue process. PJM shall document the fault clearing time requirements and/or any additional protection requirements in its Impact Study report. PJM shall also communicate the requirements on the generation side to the GO requesting the Interconnection in PJM Queue. For the transmission related requirements, DEV shall communicate these to the Substation Engineering group for design and implementation.

E. Nuclear plant interface coordination

E.1. Introduction

Nuclear power plants have special needs for backup station service not found in other plants. In order to safely shut down a nuclear unit, the station service must have an adequate supply of power under tight voltage tolerances to the safety systems. Although nuclear plants have diesel generators as a backup supply, their preferred power source is the transmission grid. This allows multiple levels of redundancy which is the hallmark of the nuclear plant's endeavor to the highest level of safety.

E.2. NRC regulations

The Federal Nuclear Regulatory Commission (NRC) lays out certain regulations on the design and operation of Nuclear Plants. **Appendix A of Regulation 10 CFR 50** "General Design Criteria for Nuclear Power Plants" states:

> *"Criterion 17--Electric power systems. An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other*

vital functions are maintained in the event of postulated accidents.

The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss-of-coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies."

The above regulation General Design Criterion 17 is often abbreviated "GDC-17."

E.3. Design requirements

PJM and Dominion Energy Electric Transmission Planning will design the system to meet the GDC-17 requirements. In order to provide adequate voltage to safety systems, the Nuclear group periodically provides Nuclear Plant Interface Requirements (NPIR) to Dominion Energy Electric Transmission. Dominion Energy transmission planners should consult the latest version of applicable Interface Agreements between Dominion Energy Electric Transmission and the nuclear plants for applicable normal and emergency voltage limits, voltage drops and contingency scenarios.

Because emergency systems require adequate voltage immediately following an event, transmission LTC's should be locked post-contingency.

For violations of the NPIRs, the transmission planner will contact the GDC-17 coordinator for Electric Transmission Planning. PJM/Dominion Energy Electric Transmission Planning will notify Dominion Energy Nuclear of any NPIR criteria violations. Transmission study criteria violations based on standard PJM/Dominion Energy criteria testing will be handled by the procedures described in the PJM agreements and manuals. For study violations that are beyond applicable PJM criteria, Dominion Energy Nuclear will determine if any further action is required and respond to Dominion Energy Electric Transmission Planning. Dominion Energy Electric Transmission Planning will work with PJM to resolve concerns identified by Dominion Nuclear.

For contingencies more severe than those within the NPIRs, standard planning voltage range criteria will be applied.

E.4. Underfrequency studies

The underfrequency load shed program (UFLS) should be designed to coordinate with station underfrequency trip settings. The North Anna reactor coolant pump (RCP) is set to trip at 56.55 Hz with a time delay of 100 milliseconds. The Surry reactor coolant pump (RCP) is set to trip at 58.05 Hz with a time delay of 100 milliseconds.

E.5. Angular stability studies

Angular stability studies are performed on nuclear plants using the standard methodology used for any synchronous machine. The results of these studies should be forwarded to Nuclear Engineering.

E.6. System analysis protocol

The Nuclear Switchyard Interface Agreement System Analysis Protocol (CO-AGREE-000-IA1-4 or its successor) outlines the types and frequency of studies which may be performed in support of the nuclear plant. It also specifies the type of communications necessary and the frequency of the analysis. In order to show compliance with NERC Standard NUC-001-2 (or its successor), the GDC-17 coordinator shall retain evidence of communications with the appropriate nuclear contacts.

E.7. Changes to the system

The NERC standard NUC-001-2, R8 states that the "…Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs."

F. References

- NERC Planning Standard TPL-001
- NERC PRC Standards 12 - 17
- Transmission System Performance SERC Supplement
- NERC Reliability Standard NUC-001
- Nuclear Switchyard Interface Agreement CO-AGREE-000-IA1
- Nuclear Switchyard Interface Agreement System Analysis Protocol CO-AGREE-000-IA1-4

- PJM Manual 39 – Nuclear Plant Interface Coordination
- Manual 14B – PJM Region Transmission Planning Process

G. Abbreviations & definitions

- **AAR** - Auction Revenue Rights (see PJM Manual 06 – Financial Transmission Rights for more details)
- **ANSI** - American National Standards Institute
- **ERAG** - Eastern Interconnection Reliability Assessment Group
- **FCITC** - First Contingency Incremental Transfer Capability
- **Good Utility Practice** - Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition.
- **GSU** - Generator Step-up Transformer
- **IEEE** - Institute of Electrical and Electronic Engineers
- **MMWG** - Multi-Regional Modeling Working Group
- **NERC** - North American Electric Reliability Corporation
- **POI** - Point of Interconnection
- **RTO** - Regional Transmission Organization
- **PSS** - Power System Stabilizer
- **SERC** - SERC Reliability Corporation

H. Revision History

Revision Date	Revision #	Description	Revised By	Effective Date
08/24/1999	0.0*	Original document created to meet the requirements of NERC Planning Standard I.C.S1.M1.	ET Planning staff	08/24/1999
05/01/2001	1.0*	See Details for Revision 1.0 below	ET Planning staff	05/01/2001
09/07/2005	2.0*	See Details for Revision 2.0 below	ET Planning staff	09/07/2005
05/29/2007	3.0*	See Details for Revision 3.0 below	ET Planning staff	05/29/2007
12/22/2009	4.0*	See Details for Revision 4.0 below	ET Planning staff	12/22/2009
12/22/2011	5.0*	See Details for Revision 5.0 below	William F. Bigdely	12/22/2011
10/10/2012	6.0	See Details for Revision 6.0 below	William F. Bigdely	10/10/2012
11/22/2013	7.0	See Details for Revision 7.0 below	William F. Bigdely	11/22/2013
03/31/2014	8.0	See Details for Revision 8.0 below	William F. Bigdely	03/31/2014
07/16/2014	9.0	See Details for Revision 9.0 below	William F. Bigdely	07/16/2014
01/09/2015	10.0	See Details for Revision 10.0 below	William F. Bigdely	01/15/2015
03/26/2015	11.0	See Details for Revision 11.0 below	William F. Bigdely	03/27/2015
12/15/2015	12.0	See Details for Revision 12.0 below	William F. Bigdely	01/01/2016
05/15/2017	13.0	See Details for Revision 13.0 below	William F. Bigdely	06/01/2017
03/29/2018	14.0	See Details for Revision 14.0 below	William F. Bigdely	04/01/2018
12/13/2018	15.0	See Details for Revision 15.0 below	William F. Bigdely	01/01/2019
03/11/2019	16.0	See Details for Revision 16.0 below	William F. Bigdely	03/15/2019
03/10/2020	17.0	See Details for Revision 17.0 below	David C. Witt	03/24/2020
06/22/2020	18.0	See Details for Revision 18.0 below	David C. Witt	07/01/2020
02/22/2021	19.0	See Details for Revision 19.0 below	Hamidreza Sadeghian	04/01/2021
03/03/2022	20.0	See Details for Revision 20.0 below	Mark Gill	04/01/2022
02/16/2023	21.0	See Details for Revision 21.0 below	Amirreza Sahami	04/01/2023

*For these revisions, the planning guideline was an attachment within the DEV facilities connection requirements document. Associated comments for these revisions do not necessarily apply to the contents of the planning guideline specifically.

Details for Revision 1.0

- Revised to include information regarding Dominion's generation interconnection procedures/process

Details for Revision 2.0

- Revised to reflect transition from old NERC Planning Standards to NERC Reliability Standards, including changing the naming convention of all referenced standards throughout the document.

Details for Revision 3.0

- Revised to reflect the following:

  - Updates to NERC Reliability Standards
  - Dominion's PJM Membership
  - References to new SERC regional studies processes

Details for Revision 4.0

- Revised to reflect the following :
  - PJM Generation Queue Changes Section 4
  - General Revisions all sections

Details for Revision 5.0

- Revised the following:
  - Section 2.12: Clarified content regarding synchronizing of facilities.
  - Exhibit A: Changed loading criteria to not exceed emergency rating of transmission facility.
  - Various errata changes.

Details for Revision 6.0

- Overhaul and expansion of entire Planning Criteria.
- Document previously called "Transmission Planning Guidelines"

Details for Revision 7.0

- Updated to include future reference to TPL-001-4 (R1 and R7 NERC enforcement date of 01-01-2015)
- Updated titles for approval process
- Various errata changes

Details for Revision 8.0

- Expanded description for Section G.1. TAPPING LINE BELOW 100 MW LOAD to emphasize the requirement of a fused bypass arrangement.
- Recreated diagrams throughout for consistency of style.

Details for Revision 9.0

- Added section C.2.8 - End of life criteria
- Reformatted headers to improve PDF navigation via bookmarks.

Details for Revision 10.0

- Clarifications and annual review.
- Reformatted approval area and moved to title page.
- Reformatted Revision History and moved to end of document (Section J).
- Modified throughout to reflect NERC Reliability Standard TPL-001-4, including replacement of Tables 1A and 1B and deletion of "Category D Multiple Testing Requirements" (previously Section C.2.7 in Revision 9.0 document).

- Section C.2.6 Radial lines: Expanded to introduce new criteria and metrics.
- Section C.2.7 Network transmission lines – Limitations on direct-connect loads: Inserted new section.
- Section D.4 Study cycle – Clarified that PJM (not DEV) performs simulations to cover all generating plants over a three-year study cycle (not five-year).
- Section G: Modified electrical arrangements and clarified lines of demarcation.

Details for Revision 11.0

- Section C1, Table 1A Notes – Added Note “C”
- Section C1, Table 1B Notes – Added Note “G”; re-numbered other notes to differentiate from Table 1A [Note G became Note I in v15]
- Section D7 Selection of generation dispatch – Rephrased the content to improve clarity.

Details for Revision 12.0

- Changed references of Special Protection System (SPS) to Remedial Action Scheme (RAS).
- Tables 1A and 1B: Removed references to DC line (does not apply to Dominion), and
- Table 1A, Note B and Table 1B, Note F: Clarified “may NOT be required if the loss of consequential and non-consequential load up to 300MW achieves a return to the STE rating.”
- Section E.3. Updated NPIR Limits.
- Former Section F (Transmission Line Connections – Generation) and former Section G (Load Criteria – End User) have been removed from this document and integrated into the Facility Interconnection Requirements as Sections 5 and 6.
- Section G Abbreviations & definitions: Added definition of “Good Utility Practice”.

Details for Revision 13.0

- Revised references for new Dominion Energy corporate identity.
- Section C.1. Added Table 1C Steady-State Performance EXTREME Events and Dominion Energy CRITERIA, and associated notes; refined notes for Tables 1A and 1B.
- Added Section C.2.8. Substation – Limitation on direct-connect loads.

Details for Revision 14.0

- Clarified that some notes to Tables A, B and C are “Dominion Energy” notes.
- Edited Dominion Energy Note “B” for Table 1A and Note “F” for Table 1B to remove phrase “and non-consequential” [load]. [Note F became Note H in v15]
- Edited Dominion Energy Note “C” for Table 1A and Note “G” for Table 1B to refer to new section C.2.1.3. [Note G became Note I in v15]
- Added Section C.2.1.3 - Critical stress case development and studies

Details for Revision 15.0

- Reviewed to ensure alignment with Facility Interconnection Requirements, v15, effective 1/1/2019.
- Tables 1A, 1B, 1C: Added new notes to Tables 1A and 1B, requiring re-labeling of notes in Tables 1A, 1B and 1C as follows:

Previously	Now
A	**A**
B	**B (edited)**
-	**C (NEW)**
C	**D**
-	**E (NEW)**
D	**F**

Previously	Now
E	**G**
F	**H**
G	**I**
-	**J (NEW)**
H	**K**
I	**L**

Previously	Now
J	**M**
K	**N**
L	**O**
M	**P**
N	**Q**

- Section C.1. Planning principles and standards - Simplified reference to Nuclear generation re-dispatch.
- Section C.2.9. End of life criteria - Edited discussion and list of factors considered.
- Section C.3. Selection of generation dispatch used in DEV Power Flow Studies - New section.
- Section E Nuclear plant interface coordination:
    - E.3. Design Requirements – Removed tables of NPIR voltage limits, voltage drops, and contingency scenarios.
    - E.7. Changes to the system – Simplified content to contain only the NUC-001-2, R8 quotation.

Details for Revision 16.0

- Table 1A, Note B: Deleted specific reference to 230 kV (table applies to several voltages).
- Table 1B, Notes F & G: Removed specific references to 500 kV (500 kV is inherent to this table).

Details for Revision 17.0

- Updated dates, names and revision number.
- Tables 1A and 1B – Added contingency for Category P4, Event 6
- Section C.1 Planning principles and standards – Added language describing N-1-1 contingency analysis.
- Section C.2.6. Radial transmission lines – Edited discussion.
- Section C.2.9. End of life criteria – Removed evaluation of lines operating below 500kV and edited assessment language.
- Section D Transmission planning, system stability criteria – General update of this section including language expanding the stability study horizon beyond 5 years to accommodate longer term strategic projects.
- Section F – Updated to include reference to PRC Standards 12 -17.

Details for Revision 18.0

- Table 1A – Decreased the high voltage limits for 138kV lines.
- Table 1B – Revised the high voltage limits for 500kV and above lines.
- Table 1C – Revised Note “Q” Extra High Voltage (EHV) limit to 109.6%.

Details for Revision 19.0

- Updated Signature Page.
- Section C.1 Planning principles and standards – Revised time frame of system adjustments.

- Table 1A – Removed the Note “A”, “B”, and “C” and set the Thermal Limits to 100% of Short Term Emergency (STE). Note C added for system adjustments at initial condition in P3 and P6. In addition, system reinforcements for load loss more than 300 MW are indicated.
- Table 1B – Removed the Note “F”, “G”, and “H” and set the Thermal Limits to 100% STE. Note F added for system adjustments at initial condition in P3 and P6. In addition, system reinforcements for load loss more than 300 MW are indicated.
- Table 1C – Changed the Note References.

Section C.2.2. Added footnote for DEV criteria on Generation Deliverability.

Details for Revision 20.0

- Updated Signature Page.

Details for Revision 21.0

- Updated Signature Page.
- Minor typos and grammatical edits through the entire document.
- Section C.1., Table 1A, Table 1B: P5 is updated to include future reference to TPL-001-5.1 (Effective date is 07/01/2023).
- Section C.1., Note 13 is updated to include future reference to TPL-001-5.1 (Effective date is 07/01/2023).
- Section C.2.6 Radial transmission lines criteria is modified to address wider range of situations.

REQUEST/NOTIFICATION FOR CHANGES IMPACTING DOMINION ENERGY VIRGINIA (DEV) FACILITIES

Customer shall initiate requests to install, modify, or remove Dominion Energy Virginia's (DEV) Facilities, or to modify the capacity or characteristics required at a Delivery Point, or to discontinue the delivery of electricity to a Delivery Point, in writing using the Request/Notification for Changes Impacting Dominion Energy Virginia (DEV) Facilities form included in this [form]. Customer shall also submit a Request Form when making changes to Customer's Facilities that are reasonably anticipated to (i) lead to a modification to Dominion‟s Facilities or (ii) impact the operation of DEV‟s Facilities.

The Request Form shall be submitted by Customer as soon as useful information is available. As additional or updated information becomes available, Customer shall make timely submission of a revised Request Form. For Request Forms submitted with notations of "(E)" or "TBD by *[date]*" as described below, the Parties shall determine a schedule for the provision of complete and final information.

1. Customer shall, in accordance with the following requirements, provide, on a timely basis, information that is complete and accurate. On every Request Form submitted, each blank (including items such as "Additional Comments" and "Other Milestones") shall contain one of the following entries:

   1.1. The firm (e.g., final) information.

   1.2. If no information is appropriate for a given item, the entry "N/A."

   1.3. An entry as further described below:

      1.3.1. In Sections II, III, and IV, an entry initially marked as "(E)." Such entries shall be revised with firm information as soon as it is available. If the "Requested Date to Energize" in Section IV is initially marked as (E), then the firm date ultimately supplied for "Requested Date to Energize" shall be on or after the estimated date unless an earlier firm date for "Requested Date to Energize" is mutually agreed-upon prior to submission of a revised request form.

      1.3.2. In Section III, an entry may be "TBD by *[date].*" Additionally, each of the Required Attachments of Section III shall be provided, or shall be substituted by a page bearing the attachment description and the date by which the attachment shall be provided.

2. Upon receiving a request, DEV shall evaluate such request within its ordinary course of business and consistent with the PJM Requirements. The evaluation may include the investigation of alternate solutions to accommodating Customer's needs. Customer to reasonably assist DEV‟s evaluation, including, without limitation, the provision of additional information and participation in a cooperative review and exploration of the request and its alternatives. DEV shall not be required to complete such evaluation until a reasonable time after the Customer has supplied all information as firm information.

3. Upon concluding its evaluation, DEV shall provide a written response approving the request, approving the request with modifications, or denying the request. Any modification or denial shall not be unreasonable and shall be accompanied by the reasoning for such determination. In the event of approval or modified approval, the response shall describe, consistent with the Agreement, any required construction or modifications by the Parties, any estimated Project costs, cost responsibilities between the Parties, and other actions the Parties must take to implement the request in its approved form.

REQUEST/NOTIFICATION FOR CHANGES IMPACTING DOMINION ENERGY VIRGINIA (DEV) FACILITIES

SECTION I – GENERAL Date: / / 20 Revision No.:

Requestor Name: ______________________________

Requestor Address: ______________________________

____

Name of Contact Person: ______________________________

Contact's Phone: - - ext. Contact's Cell: - -

Contact's Fax: - - Contact's Email: ______________________________

Signature below authorizes Dominion to proceed with design, engineering, and estimation of Project cost as appropriate for DEV to evaluate and respond to this request. This authorization is pursuant and subject to all terms and conditions of the Agreement of which this Appendix is a part.

Authorizing Signature: ______________________________ Auth. Date: / / 20

Printed Name: ______________________________ Phone: - -

Title: ______________________________

SECTION II – DESCRIPTION OF REQUEST

Name of Delivery Point:	
Brief Description of Request: (attach detail)	
Brief Reasoning for Request: (attach detail)	
Delivery Point Location: (attach detail if DP is new)	
Noteworthy Load Characteristics: (large motors, large fluctuating loads, large harmonic-producing loads, etc.)	

PRESENT DELIVERY POINT DATA:

Present Delivery Point Voltage: ____________________

Present Maximum kVA Capacity of Delivery Point Facilities: ____________________

Present Summer Peak kW Demand: __________ Present Summer Peak kVAR Demand: __________

Present Winter Peak kW Demand: __________ Present Winter Peak kVAR Demand: __________

ANTICIPATED NEW DELIVERY POINT FACILITES DATA:

New Delivery Point Voltage: ____________________

New Peak kVA Capacity of Delivery Point Facilities: ____________________

Peak kW and rkVA During First Three Years Following Implementation and Highest Peak Within Ten Years:

	Initial Year:	Second Year:	Third Year:	Highest in First Ten Years:
Enter Year ➔				
Summer Peak kW:				
Summer Peak rkVA:				
Winter Peak kW:				
Winter Peak rkVA:				
Delivery Point Facilities Route:				

(attach detail if new line extension is involved) ____________________

Additional Comments: ____________________

SECTION III – CUSTOMER'S EQUIPMENT

Transformer Primary Voltage: __________ Transformer Secondary Voltage: __________

Transformer Nameplate Capacity: __________ Temperature Rise: __________

Transformer Taps: ____________________

Connection (e.g. Wye-Wye): ____________________

Transformer Impedance: ____________________

Isolation Device Type and Rating: ____________________

Protection Device Type and Rating: ____________________

Required Attachments: [1] One-line diagram [2] Transformer test report [3] Transformer loss curve
[4] Operating procedures description [5] Protection scheme functional diagram
[6] Protection Device information (including device types, serial and model numbers, relay settings, etc.)

SECTION IV – TIMING

Request included in Customer's planning documents submitted to Dominion on:

Most Recent Submission: / / 20 Second Most Recent Submission: / / 20

Expected Date Customer's Construction to Commence: / / 20

Expected Completion Date of Customer Work: / / 20

Date Requested for Dominion Construction to Commence: / / 20

Requested Completion Date of Dominion Work (De-energized): / / 20

Requested Date to Energize: **(See Note)** / / 20

Other Milestones:

NOTE: If the "Requested Date to Energize" is marked as (E), then the firm date ultimately supplied must be on or after the estimated date, unless an earlier firm date is mutually agreed-upon prior to submission of the revised request form.

(E) = Estimated

N/A = Not Available

TBD = To Be Determined

Dominion Energy Virginia
Generator Interconnection Protection Requirements

Author Name and Title	Signature	Date Reviewed
Daniel Ridenour Engineer III, ET System Protection Standards	Daniel Ridenour	11/27/2023

Approved By Name and Title	Signature	Date Reviewed
Philip VanSant Manager, ET Engineering Standards	Philip VanSant	11/26/2023

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Table of Contents

LIST OF FIGURES AND TABLES

ABBREVIATIONS

CCVT (also CVT) – Coupling Capacitor Voltage Transformer (similar to Capacitor Voltage Transformer)

DCB – Directional Comparison Blocking

GSU – Generation Step-Up Transformer

IBR – Inverter Based Resource

MW – Megawatt(s)

N-1 – Single Contingency Outage (Normal minus One Transmission Element)

OPGW – Optical Ground Wire

PCC or POI – Point of Common Coupling or Point of Interconnection

PJM – Regional transmission organization of which Dominion Energy is a member (www.pjm.com)

PLC – Power Line Carrier

SIR – Source Impedance Ratio

DEFINITIONS

Transmission Element – Transmission elements are primary equipment (69 kV and above) that constitutes, or interconnects with, the Dominion Energy Electric Transmission System. Examples include buses, lines, or transformers with low side voltage 69 kV or above, regardless of Bulk Electric System status.

Breaker Failure Transfer Trip - Trips remote sources in the event of a breaker failure.

Customer Interconnected Generation Station or Customer Interconnected Collector Station – Customer owned substation containing line or collector line terminals, breakers, transformers, and protection, metering, and monitoring equipment

Dominion Energy Interconnected Switching Station – Dominion Energy owned substation containing line terminals, breakers, transformers, and protection, metering, and monitoring equipment. The Dominion Energy Interconnected Switching Station is included as a line terminal transmission substation.

Islanding Transfer Trip - Trips interconnection in the event a generating facility is operating disconnected from the transmission grid

Line Transfer Trip - Trips remote sources that are not capable of clearing a fault because current magnitude is below the protective relay scheme setpoints.

Networked Transmission Line – A transmission line that connects to two or more network transmission sources (lines and/or substations).

Radial Transmission Line - A radial transmission line is defined as a single line that has one transmission source and does NOT tie to any other transmission network source (line or substation).

Transmission Tap Line – A transmission tap line is defined as a radial line that connects to either a network or radial transmission line. Dominion Energy Facility Interconnection Requirements diagrams 5.3.2.A and 5.3.2.B provides examples.

N-1 – Contingency analysis for determining relay settings. This may be the lowest flow first contingency outage, or the highest flow first contingency outage depending on the relay element being analyzed.

Power Line Carrier (also Carrier; PLC) – Higher frequency signal coupled to the AC transmission system used to transmit one bit of information

1 PURPOSE AND INTRODUCTION

Virginia Electric and Power Company is commonly referred to as Dominion Energy.

The purpose of the *Dominion Energy Electric Transmission Generator Interconnection Protection Requirements* document is to provide protection requirements and expectations to any individual or group seeking to connect electric power generation to Dominion Energy's electric transmission system.

Two primary drivers for these protection requirements are safety of personnel and customers, and the reliability of the electric transmission system.

This document supplements Dominion Energy's Facility Interconnection Requirements document.

2 WIDE AREA PROTECTION AND ISOLATION

Boundary analysis and protection studies are required for identifying transfer-trip and anti-islanding requirements. Transfer trip and anti-islanding requirements are dependent on system configuration.

2.1 Line Transfer Trip Requirements

Weak, partial, or variable sources may not provide enough fault current for protective relaying to completely isolate faulted transmission elements. Dominion Energy will require installation of transfer trip equipment on all lines contained within the identified transfer trip boundary. The transfer trip boundary is expanded from the POI out to the nearest remote transmission terminal substation where three or more non-generation sources are encountered. The line connecting the interconnect station to the remote station is counted towards meeting the criteria. The line connecting to the substation, which satisfies the boundary requirement, also requires transfer trip. All transmission elements within the transfer trip boundary are subject to transfer trip requirements. Additional transfer-trip equipment (such as transfer-trip electronics, including relays and accessories, wave traps, CCVTs, etc.) may be required due to the installation of the generation station. Transfer trip equipment will also be used for breaker failure conditions outlined in Section 3.5.

2.2 Anti-Islanding Requirements

Dominion Energy will require application of its anti-islanding protection standard at all customer interconnected switching stations. Dominion Energy’s anti-islanding protection standard requires each breaker or terminal’s status within the anti-island boundary be sent to Dominion Energy’s interconnected switching station to determine whether the generation source is isolated from the rest of the electric transmission system. The purpose of the anti-islanding scheme is to prevent individual generation sources from exclusively energizing transmission elements within the islanding boundary and to prevent unsynchronized reclosing on the generator. The anti-islanding boundary is expanded from the POI out to the nearest terminal substations with three, or more, non-generation sources. The boundary substations may be included in the anti-islanding scheme depending on boundary substation configuration. The anti-islanding boundary may also be extended beyond three sources if one of the lines at the boundary exceeds its thermal limits due to unloading the generation, trips due to excessive loading, or trips due to a power swing in a power system simulation. All transmission elements within the anti-islanding boundary are subject to anti-islanding requirements. Anti-islanding schemes require separate relaying at each substation inside the anti-islanding boundary and a method to transmit breaker statuses between substations. Breaker or line terminal status will be transmitted via fiber, where available, or via power line carrier where existing fiber is unavailable and power line carrier is an acceptable transmission method (see Section 4.1 for more details).

3 INTERCONNECTION PROTECTION REQUIREMENTS

Interconnection protection requirements include specifications for fault protection of the interconnection line, breaker failure and reclosing, generation step-up transformers, and instrument transformers. Determination of the necessary protection for the POI is dependent on the individual and agregate total MW of the generation resource(s), length and configuration of the interconnection line, and technical limitations of existing facilities.

3.1 Point of Interconnection Protection Requirements

A customer-owned transformer-high-side breaker is required at the POI to separate the POI line zone of protection and the customer-owned transformer zone of protection. The customer-owned high-side breaker will be the disconnecting element should the generation source become islanded from the rest of the electric transmission system.

A high-side breaker in conjunction with a breaker ring station provides optimal isolation should a device fail to operate and initiate breaker failure (also see Section 3.5, Breaker Failure and Reclosing Requirements). To ensure reliability of the transmission system, this configuration, shown in Figure 1, is required for a POI at any network transmission line on Dominion Energy's transmission system. A high-side breaker in conjunction with a breaker ring station is also required for a POI to a radial tap line on a network line of the transmission system for an individual generation resource or the aggregate total of generation resources that is greater than 20 MW.

For simplicity, the customer interconnection generation station can be represented as a simplified single source as shown in Figure 1.

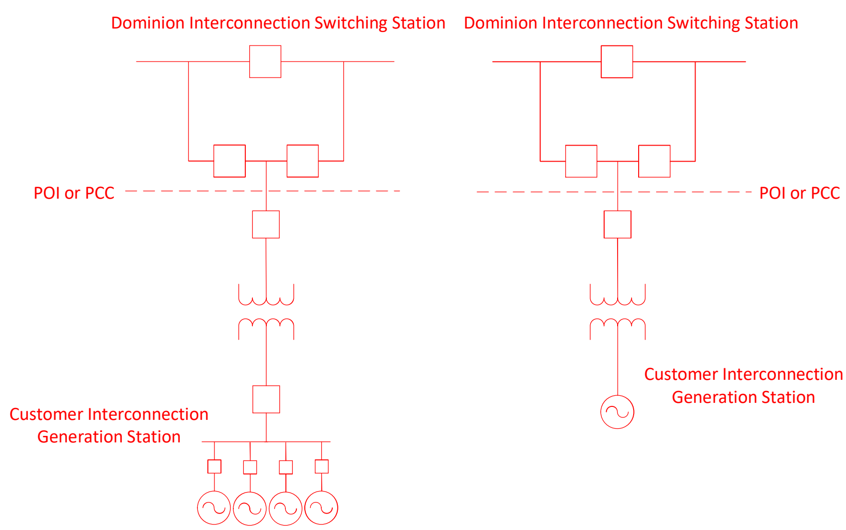

Figure 1: Complex (left) and Simplified (right) Customer Interconnection Generation Station

3.1.1 Networked Transmission Line Interconnection

The Dominion Energy Interconnection Switching Station will be a three- or four-breaker ring, or comparable layout as outlined in Section 5 of the main document [1] for generation resources of any MW size that connect to a network transmission line. A breaker station ring ensures separation in zones of protection between the Dominion Energy electric transmission system and the customer interconnected generation station. The three-breaker ring provides increased reliability as two paths are available to export power from the generation source to the electric transmission system. The breaker ring station also creates two independent zones of protection for adjacent transmission lines allowing the generator to stay online for any single momentary or sustained line outage. See Figure 2.

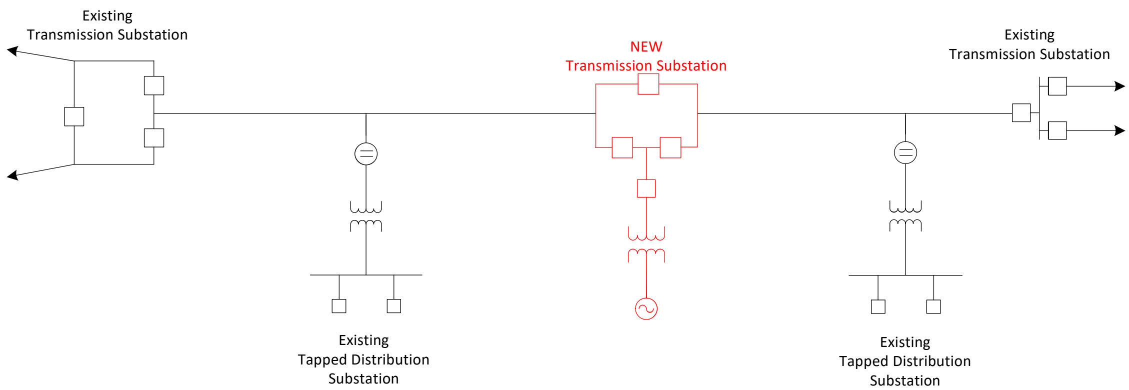

Figure 2: Network Transmission Line Interconnection

3.1.2 Transmission Tap Line Interconnection

The Dominion Energy Interconnection Switching Station may be a single breaker when the total aggregate generation resource connected to the tap line is less than or equal to 20 MW and connecting to a line segment that is tapped off of a networked transmission line (Figure 3). A breaker ring substation will be required for an individual generation resource or the aggregate total of generation resources from all sources on the tap line greater than 20 MW (Figure 4). There may be instances when the generation resource(s) connected to a tap line will desensitize the network relays and not allow proper protection. Additionally, design constraints (e.g., limitations on power line carrier or transfer trip communications channels) may prove unresolvable without system upgrades including line reconductoring, expanding communication channels, building a breaker ring station, or interfacing to the transmission system through a more distant POI. A detailed protection study will be required to determine if a breaker ring station or other upgrades are required regardless of the generation resource’s size.

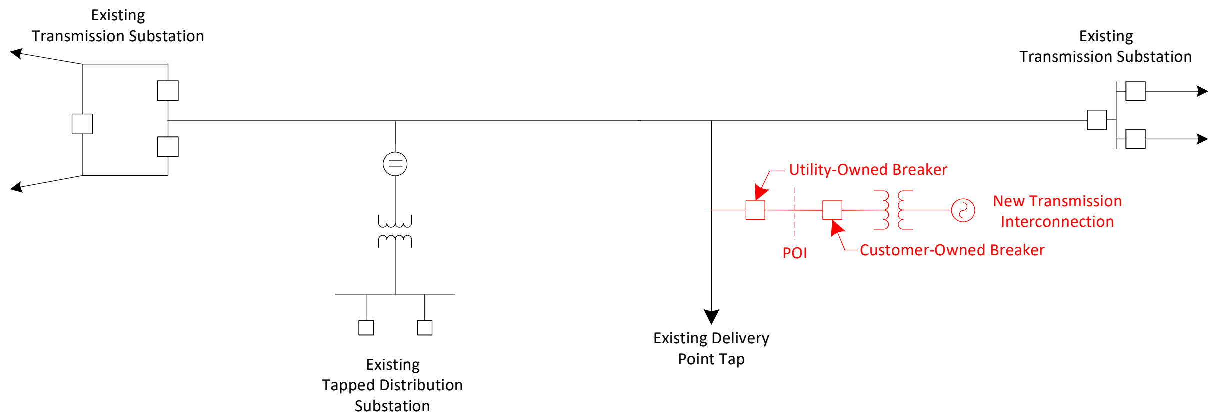

Figure 3: Typical Tap Line Customer Generation Interconnection Station (Generation Resources ≤ 20 MW)

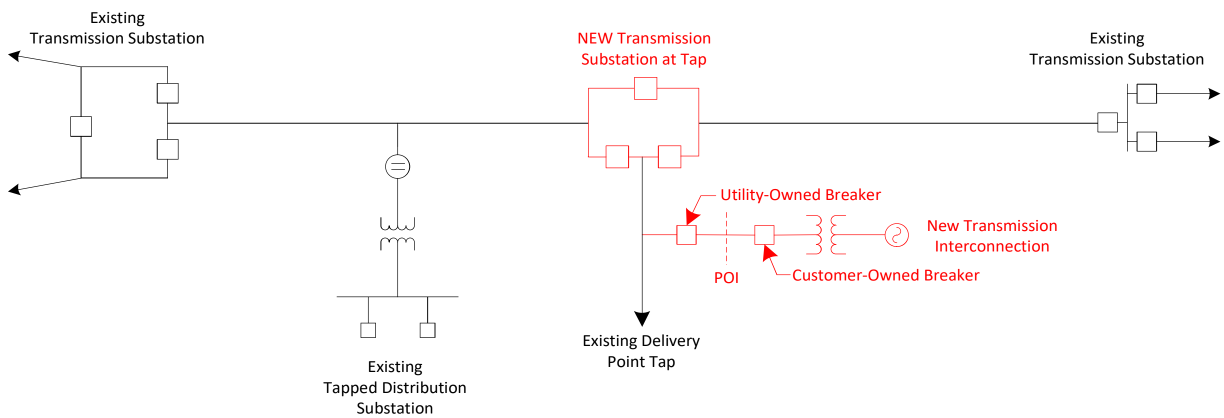

Figure 4: Typical Tap Line Customer Generation Interconnection Station (Generation Resources > 20 MW)

3.1.3 Radial Transmission Line Interconnection

The Dominion Energy Interconnection Switching Station may be a single breaker. However, generation resource POIs on radial transmission lines in Dominion Energy's transmission system must be considered on a case-by-case basis to evaluate potential reduction of relay sensitivity due to fault current contributions from the generation sources. If existing line relays cannot adequately protect against fault conditions with the addition of the generation resource, additional upgrades may be required.

3.1.4 Other Considerations

A generation resource may choose to have a breaker ring substation installed at the tap point to provide a more reliable interconnection regardless of POI, see Table 1 for further detail.

Table 1: Ring Bus Considerations

	Ring Bus connection	Single Breaker connection on tap line or radial line
Advantages	• Increased Reliability: The generation resource would have two outlets to delivery power. An outage on the networked line would only remove one side of the ring and still allow generation. • More uptime for the generation resource that leads to higher revenue. • Initial cost savings for no utility owned breaker at POI.	• Possible decrease of initial capital cost for not building line back to networked transmission line.
Disadvantages	• Possible increase of initial capital cost for building line back to networked transmission line.	• Decreased Reliability: The generation resource would only have one outlet to delivery power. An outage on the tap line would remove the generation resource from service and not allow generation. • Less uptime for the generation resource that leads to lower revenue. • Additional cost for utility owned breaker at POI.

3.2 Interconnection Generator Step-up Transformer Requirements

The customer interconnected generation step-up transformer (GSU) is required to provide a source of zero sequence current to the transmission system aiding in ground fault detection. The utility side of the GSU will be effectively grounded to prevent an excessive increase in voltage during single phase to ground faults. A GSU that can pass, but is not a source of, zero sequence current is only appropriate if a ground source is present on the medium voltage terminal, and will require evaluation prior to permission being granted. The interconnected GSU will be protected using dual high-speed current differentials.

The following transformer configurations are commonly used to meet the above requirements:

- Utility side – grounded wye, generator side – delta (typical for synchronous generation)
- Utility side – grounded wye, generator side – grounded wye, delta on the tertiary (typical for inverted-based generation)

While utility side delta – generator side grounded wye transformers are appropriate for applications in a fully radial system where energy always flows from transmission-level voltages to distribution-level voltages, this design blinds high-side residual and/or ground devices to potential problems behind the transformer. For applications in systems with the ability to produce network flows, ground sources are required.

See Section 3.7 for more details concerning modeling of generator step-up transformers.

3.3 Instrument Transformer Requirements

Three-phase capacitor coupled voltage transformer (CCVT) and current transformers (CT) connections are required for protective relaying, revenue metering, and power quality monitoring purposes at the point of interconnection.

Protection class CTs “C800” will be required for all protective relaying. Protection class CTs with “T ratings” (accuracy determined by testing) will not be used without prior approval by Dominion Energy; any CT with T800 ratings must demonstrate the same performance characteristics as C800 to be considered. Independent CTs will be used for each of the protective relays on equipment connected to transmission voltages (for example transmission lines or GSUs). If other devices (such as digital fault recorders) will share the CT secondary circuit with a protective relay, the total burden of all secondary devices and conductor will not exceed eight (8) ohms.

Accuracy class “0.15B1.8” (metering class high accuracy extended range) CTs will only be used for revenue metering or devices not used for protection. Protective relays will not be connected to metering class CTs. Additionally, no other devices will share secondary circuits on metering class CTs when used for revenue metering. The total burden of all secondary devices and conductor will not exceed 1.8 ohms.

Accuracy class “0.3WXYZ,ZZ” (metering class) CCVTs will be required. These CCVTs will be used for revenue metering. The metering class CCVT can also be used for protective relaying and other functions requiring voltage assuming the CCVT can handle the additional burden not to exceed 400 volt-amperes. If the metering class CCVT cannot handle the combined revenue meter and protective relay burden, a second three-phase CCVT with at least an accuracy class of “1.2RWXYZ,ZZ” (protection class) will be needed for the protective relays. If protective relays will be connected to any CCVT (metering or protection class), protective relays will be connected to separate secondaries on the CCVT.

3.4 Transmission Elements Requirements

Protection systems classified as dual primary are required for all equipment connected to the transmission grid at operating voltages 69 kV and above [2]. Schemes will require two independent high speed, phase and ground fault protection systems designated system one and system two. Together these systems provide a redundant set of all normal primary and backup functions.

3.4.1 Short, Medium, and Long Transmission Line Protection

All interconnections will be treated as a transmission line regardless of length and will be protected using dual line current differential relays as shown in the oneline equivalent in Figure 5. Addtionally, directionalized backup elements are required thus potential is needed at both terminals. In all cases, dedicated, redundant single mode fiber pairs will be required between the Dominion Energy Interconnection Switching Station (1) and the Customer Switching Station (2). Customers should contact Dominion Energy prior to purchasing protective relaying and fiber optic equipment and materials that plans to use to interface with Dominion Energy to obtain the Dominion Energy's latest specifications; this is to ensure that customers purchase equipment and materials that are compatible with Dominion Energy's facilities.

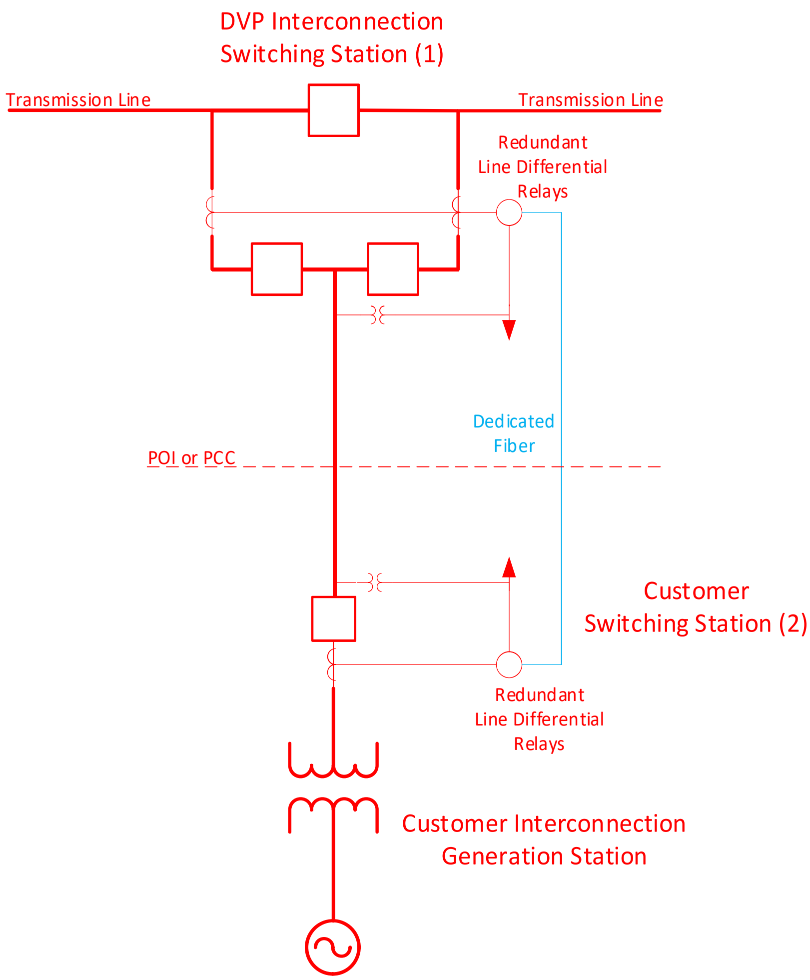

Figure 5: Interconnection Zone of Protection

3.5 Breaker Failure and Reclosing Equipment

Separate breaker failure and reclosing relays (Figure 6) will be installed on all transmission breakers (the customer-owned high-side generation step-up transformer (GSU) breaker will only require breaker failure). All breaker failure relays will be required to send transfer trip to remote stations. A reclosing synchronism check will be performed prior to the breaker closing for all time delayed reclosing attempts.

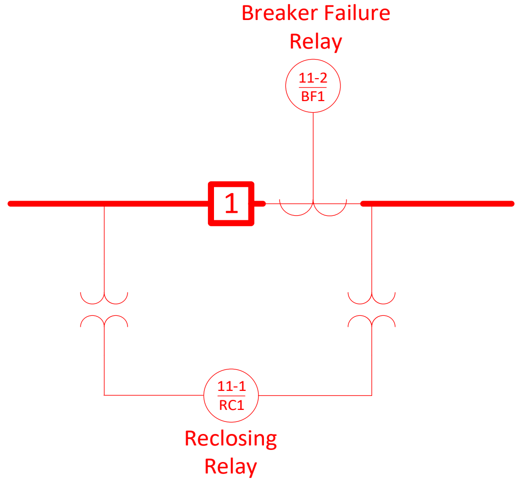

Figure 6: Breaker Failure and Reclosing Relays

3.6 Mandatory Protective Relay Element Coordination

Per NERC Reliability Standard PRC-027, all protective relay elements subject to the standard must be analyzed by Dominion Energy System Protection Engineering prior to energization. The customer will refer to the latest version of the standard to determine any protective element that must comply. The customer will communicate all applicable protective relay settings and facility drawings to Dominion Energy in an electronic form at least forty-five (45) days prior to energization. The customer will clearly identify any protective relay elements that can detect faults on the Dominion Energy transmission system. The customer's failure to provide protective relay settings and facility drawings in a timely manner may result in delayed energization.

Per NERC Reliability Standard PRC-027, in the event of future work nearby on the Dominion Energy transmission system, Dominion Energy and the customer may need to coordinate changes to protective relay elements. The customer will respond in a timely manner to communications requesting reviews of protective relay element coordination with its system. Likewise, Dominion Energy will respond in a timely manner to communications requesting reviews of protective relay element coordination with its system.

The customer will provide Dominion Energy with long-term contact information for a person or group of people who Dominion Energy can reliably contact with respect to protective relays if the need should arise. This contact will be valid in perpetuity for as long as the customer's facility is connected to the Dominion Energy transmission system. Failure to respond in a timely manner to inquiries sent to the last known good contact for a facility may result in Dominion

Energy reporting the customer's facility to SERC for violation of NERC Reliability Standard PRC-027. The customer is responsible for providing Dominion Energy updated contact information as needed. Any type of sale or transfer of ownership of the facility to another entity does not remove the new owner's obligation to respond timely to inquiries or to provide updated contact information. Customers will refer to the standard's text available on the NERC website to learn more about communication requirements.

3.7 Electrical Models of Customer Facilities

To support coordination of protective relay elements and accuracy of Dominion Energy's short circuit, planning, and operational models of the transmission grid, the customer will provide Dominion Energy with electrical models of the customer's facilities and manufacturer test reports that corroborate the customer's electrical model. The electrical models will accurately reflect the customer's facility. Therefore, all changes that may occur during the project will be communicated to Dominion Energy in new electrical models and updated manufacturer test reports that reflect the changes. The final electrical model and final manufacturer test reports for the customer's facility will be communicated electronically to Dominion Energy at least forty-five (45) days prior to energization. The electrical models will be sufficiently detailed such that Dominion Energy can appropriately assess the impact of the customer's facilities. The term "sufficient detail" means the equipment parameters needed to model the customer's facility such as but not limited to:

- Step up transformer impedance*
- Step down station service transformer impedance
- Transformer winding configuration
- Transformer voltage fixed tap selection (the fixed tap selection that will be used)
- Transmission line impedance
- For synchronous generation, unit impedances and grounding impedance
- For asynchronous generation, inverter make and model, and functionally accurate model of the inverter's controls during dynamic and short circuit system conditions

*For generation step-up transformers (the transformers connecting generation to the transmission system), a frequent choice for the transformer's winding configuration is a grounded wye-grounded wye with a *buried* delta tertiary winding. For short circuit electrical models, the buried delta tertiary is relevant to the development of electrical models for the zero-sequence network. Since the buried tertiary is not accessible for testing, customers will obtain *estimated* values for the primary-tertiary reactance and secondary-tertiary reactance based on the transformer design from the manufacturer. Dominion Energy will not contact transformer manufacturers on behalf of customers to obtain this information. The information will be present in test reports or other official documents from the customer.

Dominion Energy will not accept missing or incomplete electrical models for a facility. A customer's failure to provide adequate electrical models of their facility may result in project delays.

4 IMPACT OF NETWORKED TRANSMISSION LINE SPLIT ON LINE TERMINAL PROTECTION

In many cases, interconnection switching stations are built near an existing transmission line (Figure 7) resulting in the existing transmission line being split into two shorter transmission lines (Figure 8). The two shorter transmission lines may require protection modifications due to power line carrier or relaying constraints (ex. a medium length line now becomes two short length lines).

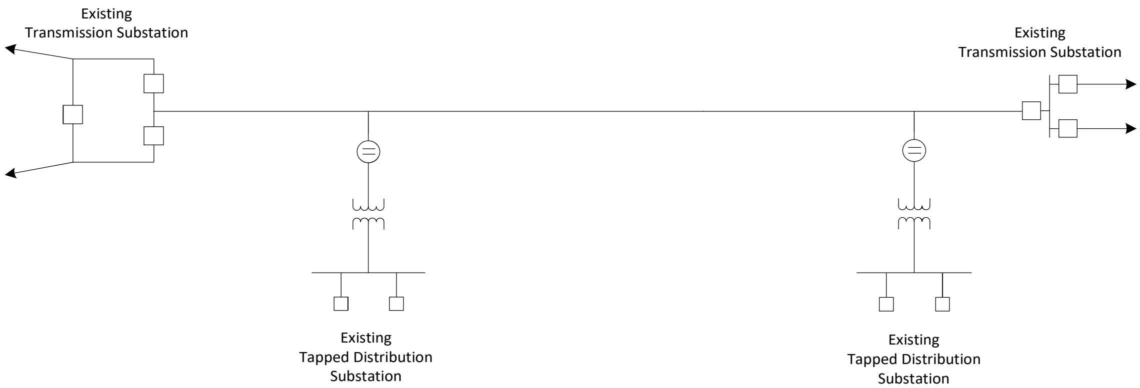

Figure 7: Existing Transmission Line

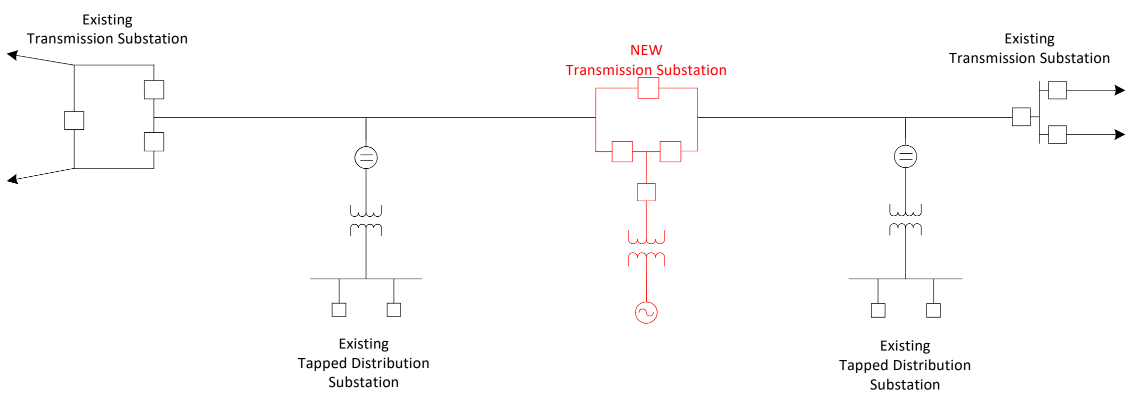

Figure 8: Transmission Line Split

4.1 Short Transmission Line Protection

Short transmission lines and line segments less than five (5) miles will be protected using dual line current differential relays. Line current differential relays require dedicated fiber be available between line and tap terminals. Relaying constraints permit the allowance of <u>one</u> tapped distribution substation within the line differential as shown in Figure 9.

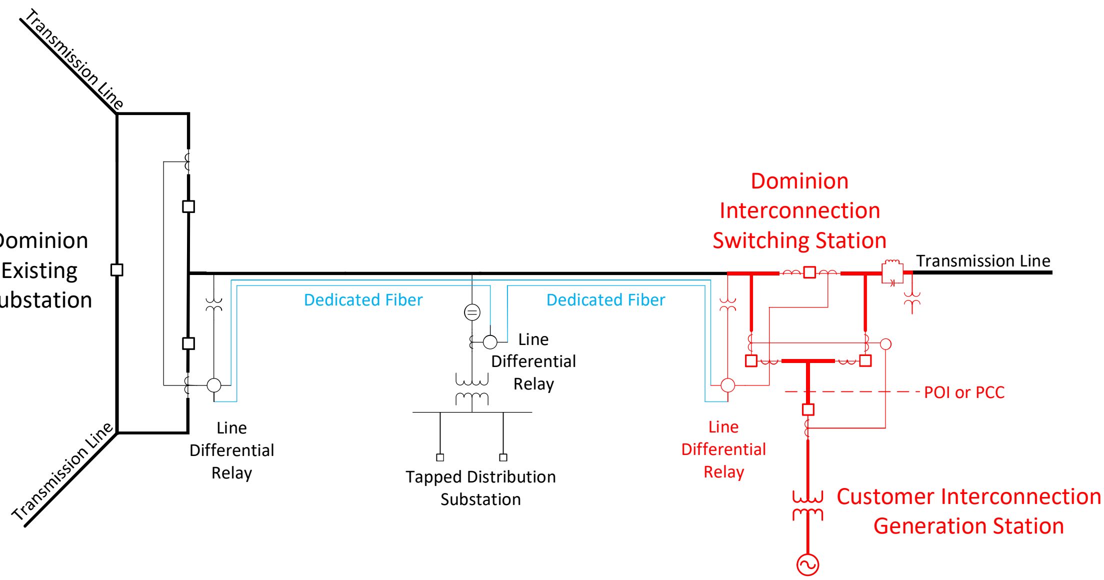

Figure 9: Short Line with Fiber

When a direct fiber connection is not available between the interconnect station (Dominion Energy Interconnection Switching Station), remote terminal station (Dominion Energy Existing Substation), and tapped distribution station, modifications to the lines, structures, towers, conduits, terminating and other equipment may be required to accomodate a direct fiber connection between the interconnect substation, existing remote substation, and tapped distribution substation. Shown in Figure 10, the 5-mile requirement is normally between line terminal stations.

If the distance between line terminal stations is greater than 5 miles and impedance relays would require carrier blocking be installed at a tapped distribution substation due to transformer penetration, then the 5-mile requirement is between the line terminal substation and the tapped distribution substation shown in Figure 11. In summary, the 5-mile requirement is between a location with a power line carrier transmitter and a location with a power line carrier receiver.

Power line carrier will **<u>not</u>** be used on transmission lines less than 5 miles long to maintain a high level of protection system dependability. Power line carrier systems coupled to short transmission lines have low signal attenuation causing several problems. Most prominently, low signal attenuation results in high voltage standing wave ratios and can cause carrier beating between opposite terminal power line carrier equipment [3] [4]. Carrier beating results in the power line carrier strength oscillating between zero and two times rated power resulting in power line carrier equipment being damaged, shutting down entirely, or misoperating.

Short lines are also problematic for impedance relaying. Transmission lines with a source impedance ratio (SIR) of 4.0 or greater are considered electrically short [5]. Source impedance ratio is the ratio of Thévenin equivalent source impedance to line impedance. Short lines protected by impedance relays are subject to transient overreach due to suppressed voltage measured at the relay, and transient instrument and relay errors [6].

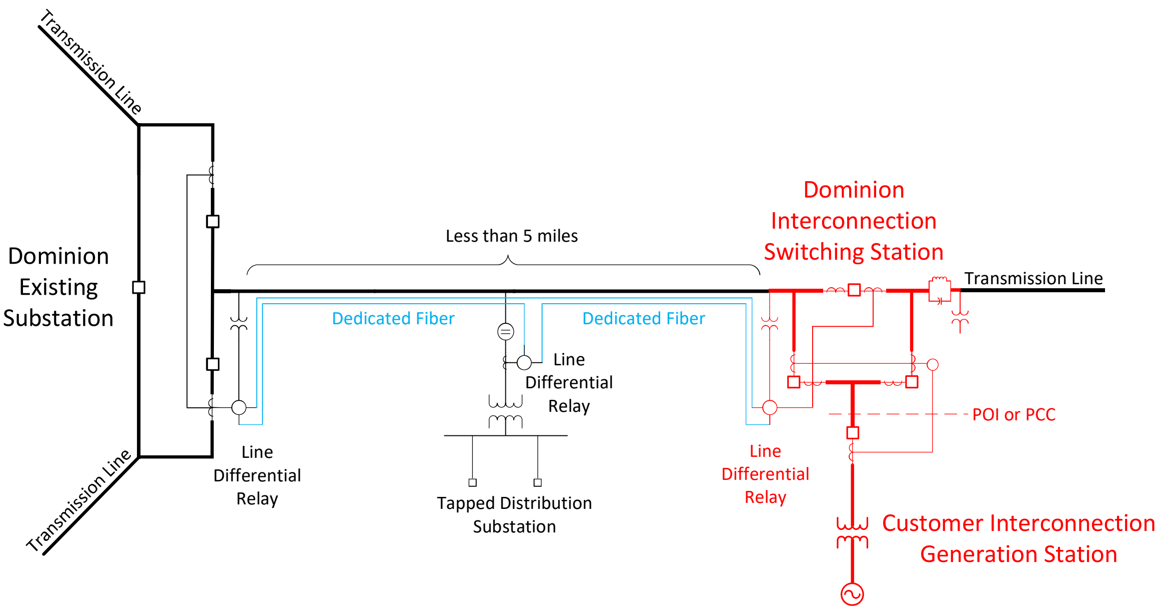

Figure 10: Traditional Zone of Protection for a Short Line

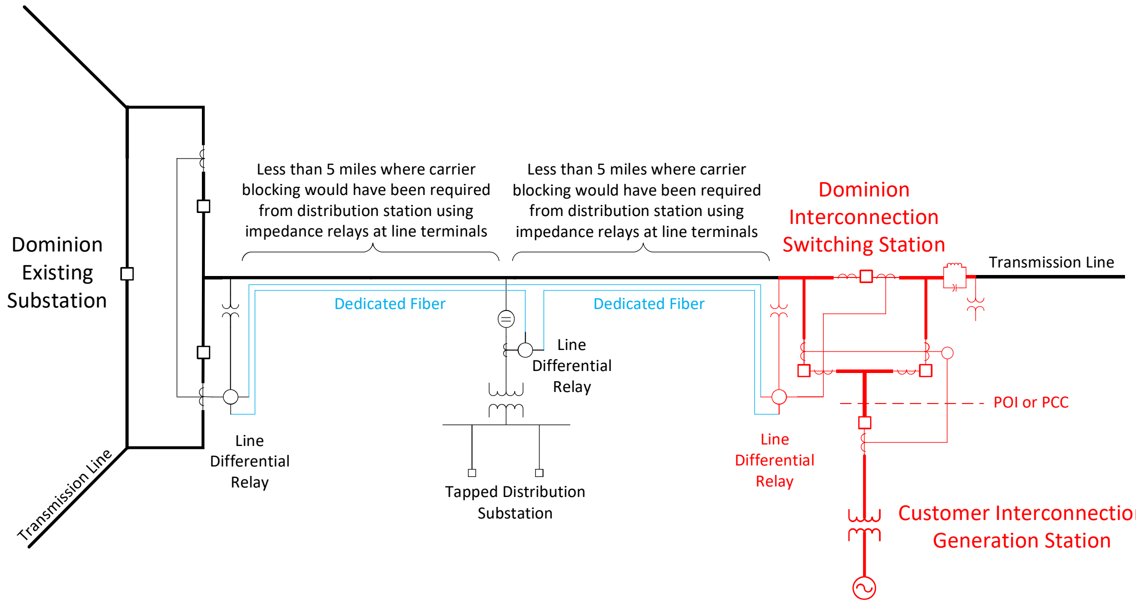

Figure 11: Medium Line Requiring Carrier Blocking at Distribution Substation Follows Short Line Requirements

4.2 Medium and Long Transmission Line Protection

Medium and long transmission lines, longer than five (5) miles, will be protected using either dual impedance or dual differential relays.

If fiber is already available on a transmission line, Dominion Energy may require customers, at its sole discretion, to upgrade existing impedance relays to differential relays at *both* terminals to mitigate the effects that inverter based resources have on fault detection and directionality detection by protection relays.

In cases where fiber exists on a line, but the line has a tapped distribution station that does not need carrier blocking at the tapped substation, Dominion Energy may require customers, at its sole discretion, to upgrade existing impedance realys to new impedance relays at *both* terminals that can accommodate a directional comparison blocking (DCB) scheme or other communication-aided scheme over fiber to help mitigate the the effects of inverter based resources.

In cases where carrier blocking is needed at a tapped distribution station or there is no existing fiber on the line, a DCB scheme via power line carrier may be specified. Regardless, customers will not be required to install fiber on transmissioin lines where the total length or the length of all line segments is longer than five (5) miles.

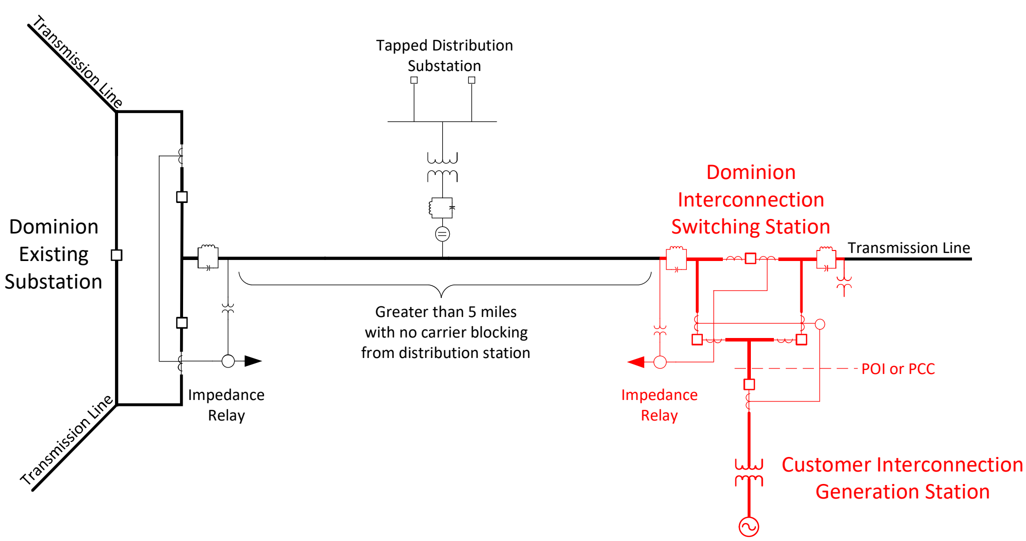

Figure 12: Medium or Long Transmission Line Zone of Protection

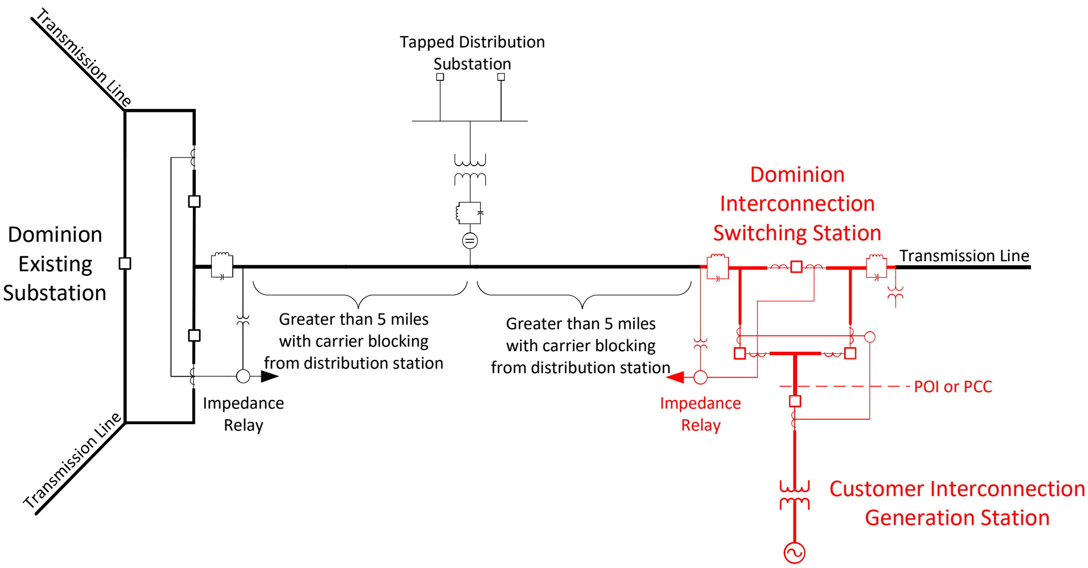

Figure 13: Medium or Long Transmission Line Zone of Protection with Carrier Blocking Tap

5 POWER QUALITY PROTECTION AT POINT OF COMMON COUPLING

Power quality relaying capable of tripping will be required at all generator interconnections for criteria listed in IEEE Standard 1159 [7] and other applicable standards. Power quality concerns associated with solar photovoltaic are reiterated in IEEE Standard 929 [8]. Protective relays can make erroneous directional determinations due to waveform distortion and other power quality issues [9]. All power quality protective elements will measure individual phase quantities. Quantities include but are not limited to:

5.1 Undervoltage (27)

An undervoltage is an RMS decrease in AC voltage.

5.2 Overvoltage (59)

An overvoltage is an RMS increase in AC voltage.

5.3 Under/Overfrequency (81/U, 81/O)

Frequency deviations above or below nominal frequency.

5.4 Reverse Power (32)

Reverse power protection may be implemented as a supervisory function or to ensure contracted power agreements are not exceeded.

5.5 Power Factor

Power factor requirements will be based on contracted power factor agreement.

5.6 Imbalance

Imbalance will be measured through differing phase quantities of voltage or current.

5.7 Waveform Distortion

Waveform distortion is defined as steady-state deviation from an ideal power frequency sinusoid characterized by the spectral content of the deviation. Five primary types of waveform distortion are DC offset, harmonics, inter-harmonics, notching, and noise.

5.7.1 Harmonics

Voltage or current harmonics may be calculated in terms of total harmonic distortion (THD) or total demand distortion (TDD) as outlined in IEEE Standard 519 [10].

5.8 Voltage Fluctuations

Voltage fluctuations are defined as a varying voltage between 0.95 and 1.05 per-unit. Voltage flicker, an undesirable result of voltage fluctuations, may be measured or monitored using methods outlined in IEEE Standard 1453 [11], which is an adoption of IEC 61000-4-15.

6 DISTURBANCE AND POWER QUALITY MONITORING

Disturbance and power quality monitoring equipment must be independent of any protective equipment used for tripping outlined in Section 2 through Section 5 and must be time synched to UTC with a satellite clock with a local UTC offset as appropriate based on equipment location.

6.1 Digital Fault Recorder Requirements

A digital fault recorder (DFR) is required at all interconnected transmission substations. This device will provide high integrity triggered oscillography (minimum 4800 Hz sampling), triggered long-term RMS plus phase data (minimum 960 Hz sampling) and continuous oscillography data (minimum 960 Hz sampling) for the purpose of disturbance location and analysis. The device must also serve as a sequence of events recorder (minimum 1 millisecond resolution) logging all circuit breaker activity. Digital fault recorder data will be the primary means for fault and event analysis. Data must adhere to the IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 [12] or later and IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 [13] or later.

6.1.1 Customers must provide breaker position for all GSU high side breaker(s) via the a-finger contacts to the utility's DFR. This is to ensure millisecond accuracy of the sequence of events report.

6.1.2 Customers must provide breaker failure lockout position for all GSU high side breaker(s) via a physical contact to the utility's DFR. This is to ensure millisecond accuracy of the sequence of events report.

6.1.3 Any additional trip paths from the Customer Interconnection site to the utility must be monitored and recorded by the utility's DFR. This is to ensure millisecond accuracy of the sequence of events report.

6.2 Phasor Measurement Units/Synchrophasors Requirements

Phasor measurement units are required at all interconnection substations to provide real time synchrophasor data to Dominion Energy's synchrophasor system. PJM Manual 14D specifies all generation greater than 100 MW must provide synchrophasor data to PJM's synchrophasor system as well.

6.3 Power Quality Monitoring

Power quality monitoring must be independent of power quality protection and may trigger on several layers of set points. Data collected from power quality monitors will strictly be used for engineering analysis.

6.4 Requests for Data from Customer Devices

Upon request from DEV, Customer power quality and Relay data will be provided electronically to Dominion Energy no later than 14 calendar days after the date requested.

Bibliography

[1] "Facility Interconnection Requirements," Section 5

[2] "Facility Interconnection Requirements," Dominion Energy, most recent version.

[3] *Special Considerations in Applying Power Line Carrier for Protective Relaying,* IEEE Power Systems Relaying Committee, Working Group H9.

[4] *IEEE Guide for Power-Line Carrier Applications,* IEEE Std 643, 2004.

[5] M. J. Thompson and A. Somani, *A Tutorial on Calculating Source Impedance Ratios for Determining Line Length,* 2015.

[6] D. Costello and K. Zimmerman, *CVT Transients Revisited - Distance, Directional Overcurrent, and Communications-Assisted Tripping Concerns,* 2012.

[7] *IEEE Recommended Practice for Monitoring Electric Power Quality,* IEEE Std 1159, 2009.

[8] *IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems,* IEEE Std 929, 2000.

[9] *Protective Relaying and Power Quality,* IEEE Power System Relaying Committee.

[10] *IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems,* IEEE Std 519, 2014.

[11] *IEEE Recommended Practice--Adoption of IEC 61000-4-15:2010, Electromagnetic compatibility (EMC)--Testing and Measurement Techniques--Flickermeter--Function and Design Specifications,* IEEE Std 1453, 2011.

[12] *IEEE Standard for Common Format for Transient Data Exchange (COMTRADE),* IEEE C37.111.

[13] *IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME),* IEEE C37.232.

7 REVISION HISTORY

Revision Date	Revision #	Description	Revised By	Effective Date
11/15/2023	6.0	See Details for Revision 6.0	Daniel Ridenour	01/01/2024
02/16/2023	5.0	See Details for Revision 5.0	Daniel Ridenour	04/01/2023
02/10/2022	4.0	See Details for Revision 4.0	Daniel Ridenour	04/01/2022
2/23/2021	3.1	See Details for Revision 3.1	Joseph Saylor	04/01/2021
12/11/2018	3.0	See Details for Revision 3.0	Douglas Ladd	1/1/2019
5/26/2017	2.0	See Details for Revision 2.0	Marlu Deverick	06/01/2017
8/17/2015	1.0	See Details for Revision 1.0	Christopher Mertz	01/01/2016
7/16/2015	0.0	Document Creation	Christopher Mertz	-

Details for Revision 1.0

- Updated short-line requirement drawings to show fiber into relaying at tapped distribution station
- Modified wording to exclude customer-owned GSU breaker from reclosing requirement

Details for Revision 2.0

- Revised references for new Dominion Energy corporate identity.
- Added additional definitions and minor sentence changes
- Updated reference 6

Details for Revision 3.0

- Added clarification for interconnections on network tap lines and radial lines.
- Expanded on Section 3.4
- Rearranged layout of several sections to improve flow of material

Details for Revision 3.1

- Updated the signature page
- Added Section 3.6 and 3

Details for Revision 4.0

- Minor formatting changes throughout document
- Expanded on Section 3.6
- Updated the signature page

Details for Revision 5.0

- Updated signature page
- Added reference to Section 3.2 pointing to Section 3.7.
- Expanded on Section 3.6
- Expanded on Section 3.7
- Minor typographical and grammatical improvements throughout document
- Removed Section 7; Attachment 5 now contains this information and additional detail

Details for Revision 6.0

- Updated signature page
- Revised Section 3.3 to add specificity about instrument transformer requirements
- Revised Section 3.4.1 to add details about fiber optic requirements
- Revised Section 4.2 to clarify requirements when customers would need to pay to install new transmission line relays and when customers would need to install fiber optic on transmission lines taps that require carrier blocking
- Revised Section 6 introduction to specify the DFRs will be UTC time synchronized *and* have an appropriate local time offset
- Revised Section 6.1 to change the continuous oscillography sample rate to 960 Hz
- Typographical and grammatical improvements throughout document

Dominion Energy Virginia
Ride-Through Requirements for Bulk Power System (BPS) Generators

Author Name and Title	Signature	Date Reviewed
Aaron Winter Engineer III, Electric Transmission Planning & Strategic Initiatives		11/27/2023

Approved By Name and Title	Signature	Date Reviewed
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Ronnie Bailey Director, Electric Transmission Planning & Strategic Initiatives		11/27/2023
Brian Starling Manager,Electric Transmission System Protection Engineering		11/27/2023
Francisco Velez-Cedeno Director,Electric Transmissioin Operations Engineering & Reliability		11/27/2023

Ride-Through Requirements for Bulk Power System (BPS) Resources

Dominion Energy's voltage ride-through requirements are derived from NERC PRC-024 and other NERC guidelines related to inverter-based resource (IBR) integration. If the inverter lacks sufficient setpoints within its internal controls, the longest ride-through time duration shall be retained for all thresholds of increasing severity. For example, if the inverter has only one (1) low voltage setpoint, the low voltage ride-through duration shall be set to three (3) seconds.

Voltage Range (p.u.)	Operating Mode	Clearing Time (s)
1.30 - 1.20	May Ride-Through or May Trip	0.30
1.20 - 1.10	Mandatory Operation	3.00
1.10 - 0.90	Continuous Operation	∞
0.90 - 0.75	Mandatory Operation	3.00
0.75 - 0.65	Mandatory Operation	2.00
0.65 - 0.10	Mandatory Operation	0.30
0.10 - 0.00	Mandatory Operation	0.15

Table 1: Dominion Energy Ride-Through Requirements (69 - 499 kV)

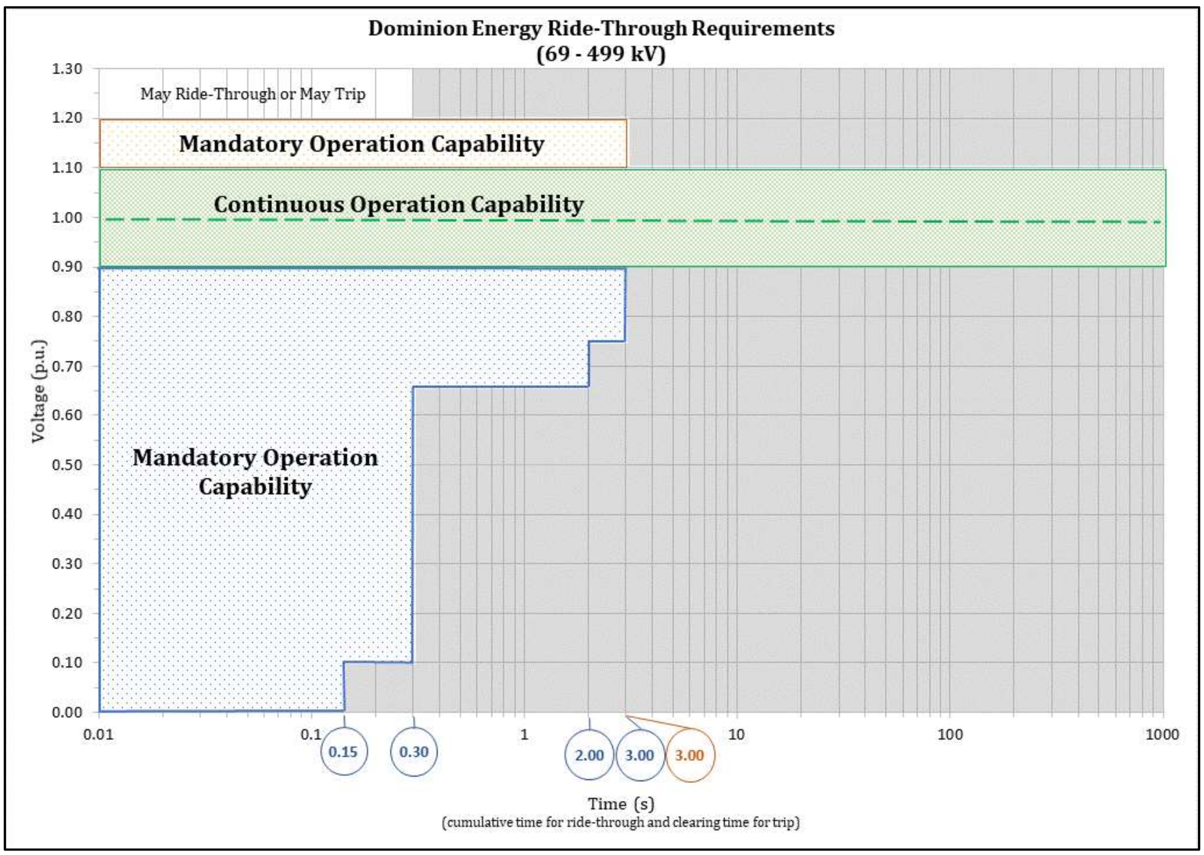

Figure 1: Dominion Energy Ride-Through Requirements (69 - 499 kV)

Generators interconnecting at 500kV must be able to continuously operate through 1.15 V_{pu}, as Dominion Energy operates the 500kV system typically between 1.00 and 1.10 V_{pu}. Ride-through requirements for 500kV interconnections as modified to accommodate the operating point.

Voltage Range (p.u.)	Operating Mode	Clearing Time (s)
1.30 - 1.25	May Ride-Through or May Trip	0.30
1.25 - 1.15	Mandatory Operation	3.00
1.15 - 0.90	Continuous Operation	∞
0.90 - 0.75	Mandatory Operation	3.00
0.75 - 0.65	Mandatory Operation	2.00
0.65 - 0.10	Mandatory Operation	0.30
0.10 - 0.00	Mandatory Operation	0.15

Table 2: Dominion Energy Ride-Through Requirements (500 kV)

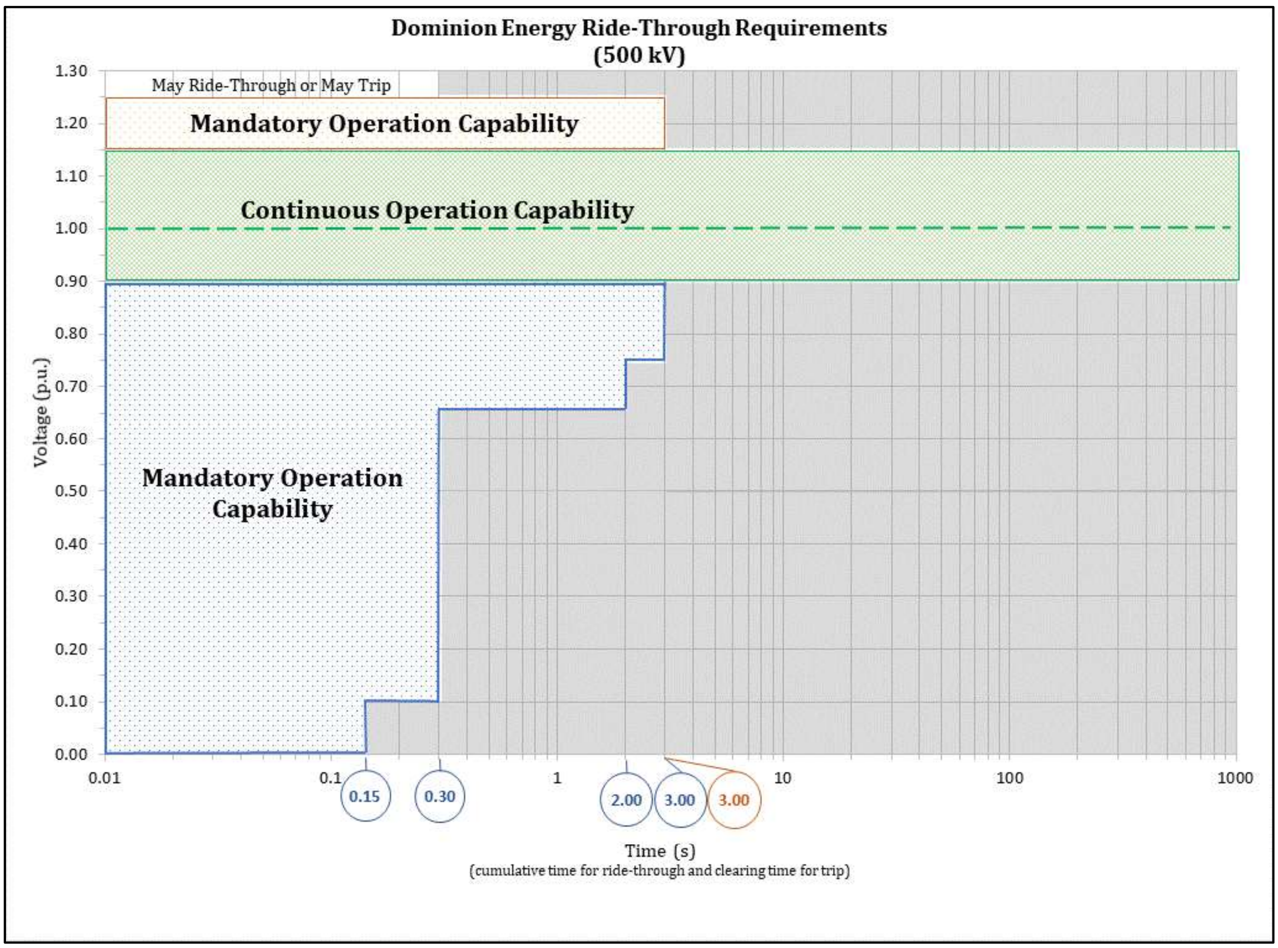

Figure 2: Dominion Energy Ride-Through Requirements (500 kV)

Dominion Energy's frequency ride-through requirements adheres to NERC PRC-024 and other NERC guidelines related to inverter-based resource (IBR) integration. The generation Interconnection Customer Facility shall have frequency ride-through capability and shall be set such that generation units remain connected during frequency excursion defined in NERC Reliability Standard PRC-024-3, Attachment 1.

Revision Date	Revision #	Description	Revised By	Effective Date
02/27/2023	3.0	Updated signature page Fixed typo in Table 2	Amirreza Sahami	04/01/2023
02/07/2022	2.0	Add frequency ride-through requirements	Jiecheng Zhao	04/01/2022
01/19/2021	1.0	Initial creation of document	Chris Mertz	04/01/2021

Dominion Energy Virginia

Generator Interconnection Data Communications and Data Exchange Requirements

Author Name and Title	Signature	Date Reviewed
Jason Lettieri Engineer III, ET Engineering Standards		11/28/2023

Approved By Name and	Signature	Date Reviewed
Philip VanSant Manager ET Engineering Standard		11/26/2023

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Table of Contents

LIST OF FIGURES AND TABLES

ABBREVIATIONS

AGC – Automatic Generation Control

BESS – Bulk Electric Storage System

CCVT (also CVT) – Coupling Capacitor Voltage Transformer (similar to Capacitor Voltage Transformer)

DEGM – Dominion Energy Generation Marketing

DE - Dominion Energy

DEV – Dominion Energy Virginia

DNP – Distributed Network Protocol

EMS – Energy Management System

FIR – Facilities Interconnection Requirements

GI – Generator Interconnection

GMS – Generation Management System

GSU – Generation Step-Up Transformer

GVL – Global Variable

MOC – Market Operations Center

MW – Megawatt(s)

MVAR – Megavar(s)

OPGW – Optical Ground Wire

PCC or POI – Point of Common Coupling or Point of Interconnection

PID - (Proportional Integral Derivative), PID controllers use a control loop feedback mechanism to control process variables

PJM – Regional transmission organization of which Dominion Energy is a member (www.pjm.com)

PPA – Power Purchase Agreement

PPC – Power Plant Controller

PQM – Power Quality Meter

RQM – Revenue Quality Meter

RTAC – Real Time Automation Controller

RTU – Remote Terminal Unit

SCADA – Supervisory Control And Data Acquisition

SCU – System Control Unit, used in the context of an inverter skid controller.

SOC – System Operations Center

DEFINITIONS

Breaker Failure Transfer Trip - Trips remote sources in the event of a breaker failure.

Generator Collector Station – Customer owned substation containing line or collector line terminals, breakers, transformers, and protection, metering, and monitoring equipment.

Dominion Energy Generator Interconnect (GI) Station – Dominion Energy owned substation containing line terminals, breakers, transformers, protection, metering, and monitoring equipment. The Dominion Energy Interconnected Switching Station is included as a line terminal transmission substation.

Islanding Transfer Trip - Trips interconnection in the event a generating facility is operating disconnected from the transmission grid.

Line Transfer Trip - Trips remote sources that are not capable of clearing a fault because current magnitude is below the protective relay scheme setpoints.

System Control Unit – For inverters that operate in a skid configuration, the SCU acts as a centralized controller for the entire skid.

Night Vars –An operational mode for PV inverters where the inverter can provide reactive power output when there is insufficient DC voltage and current to produce real power output. Battery Storage inverters have a similar mode when the unit is sitting idle between charge and discharge cycles.

No Load Reactive Support –An operational mode for certain wind turbines where in cases where there is insufficient wind to generate real power output, the turbine can still produce reactive power output.

Automatic Generation Control – A control scheme where a generator can follow a real power setpoint control signal from the centralized Generation Management System. The control signals are continuously sent, even if the setpoint remains static for a period.

Net Metering – Metering measured at the POI with Dominion Energy, where all auxiliary station service loads, transformer losses, and transmission line losses are compensated.

Gross Metering – Metering measured at the direct output of the generator and doesn’t factor in losses due to auxiliary station service loads, transformer losses, and transmission line losses.

1 PURPOSE AND INTRODUCTION

Virginia Electric and Power Company is commonly referred to as Dominion Energy.

The purpose of the *Dominion Energy Electric Transmission Generator Interconnection Data Communication and Data Exchange Requirements* document is to provide data communications architecture, data exchange, and standard SCADA application requirements and expectations to any individual or group seeking to connect electric power generation to Dominion Energy's electric transmission system.

A primary driver for these requirements is ensuring operational visibility of the interconnected facility to PJM, the Dominion SOC, the Dominion MOC/DEGM (if applicable), and local site personnel. Another primary driver is the consistent and reliable operation of standard SCADA control applications from site to site.

The primary facilities targeted with this document are for renewable energy generation like Solar, Wind, and Battery Storage. Traditional generation facilities, like fossil fuel, fired steam turbines, nuclear, and hydroelectric power stations will need to be considered on a case-by-case basis.

This document supplements Dominion Energy's Facility Interconnection Requirements document.

2 DATA COMMUNICATIONS ARCHITECTURE

2.1 GI Switching Station Data Communication

All GI switching stations will be required to have T1 or better digital communications service. The service will transmit all required metering, protection, and monitoring information from the applicable station to centrally located operational, engineering, and data servers.

2.2 Architecture Description

There are between two to four separate parallel communications paths between the generation facility and the attached Dominion Generator Interconnect Substation, depending on the site configuration, type, and operating agreement with Dominion Energy. The standard overall communications architecture between the GI substation and attached generation facility is depicted in Figure 1.

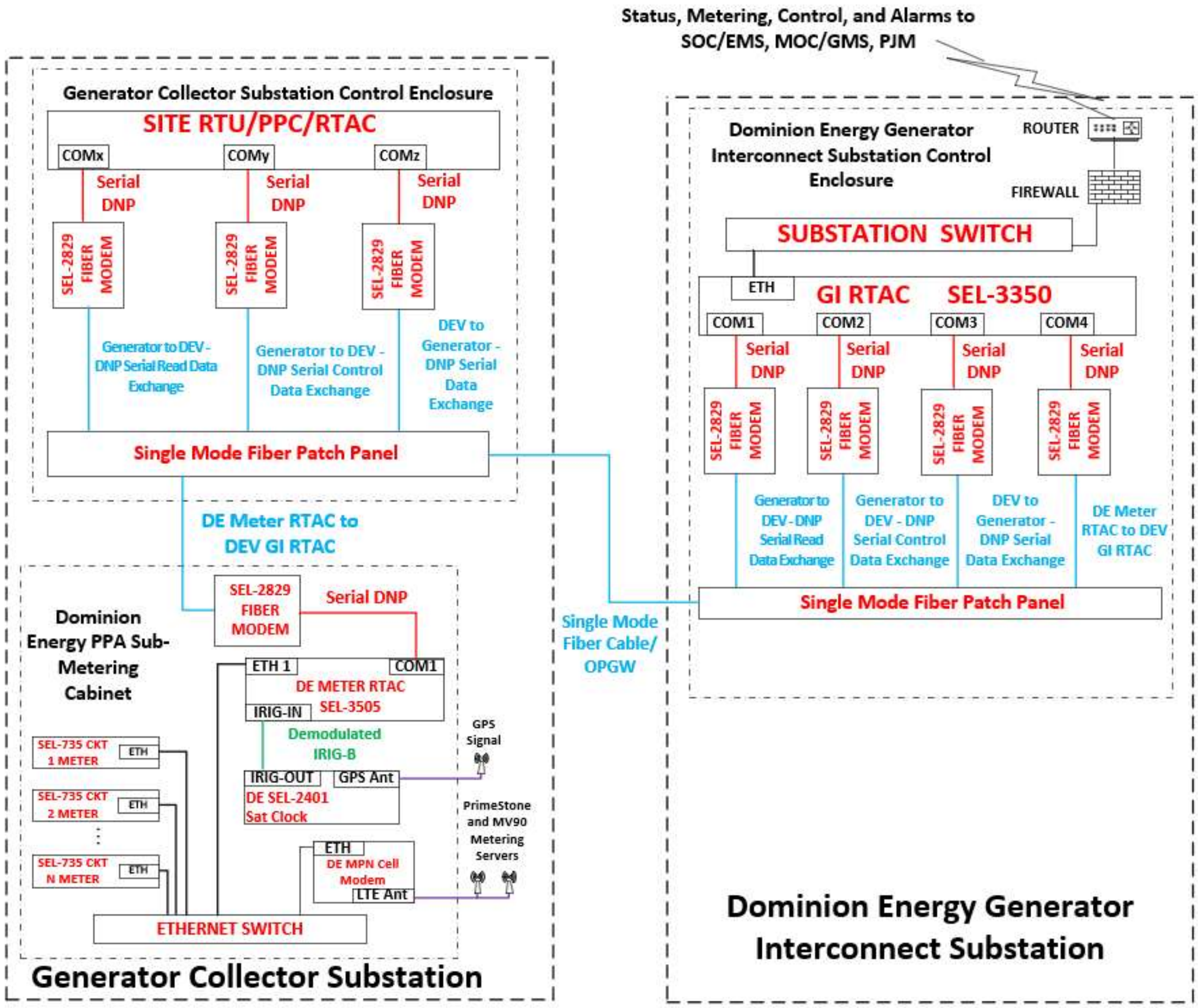

Figure 1: Generator Interconnection Substation to Generation Facility Overall Communications Architecture

The communications link between the two facilities will be single mode fiber over the optical ground wire (OPGW) or fiber cable pulled in conduit between the two attached switchyards. Usage of OPGW versus fiber cable will be dictated by distance requirements specified in the protection requirements outlined in Attachment 3 - Generator Interconnection Protection Requirements. This is the same fiber bundle also utilized for the line differential protection scheme on separate fiber pairs from the communications links. The communications method/protocol will be serial DNP3 over single mode fiber using Schweitzer SEL-2829 fiber transceivers. Each communication link will use a pair of fiber strands. Enough fiber pairs are to be pulled between the facilities to leave ample spares in case of future failures for both protection and communication applications. On either end of fiber bundle there will be a single mode fiber patch panel where the fiber pairs are terminated, individual connections will patch from these panels with single-mode fiber jumpers. The SEL-2829 fiber transceiver uses ST type fiber connectors. The fiber type is Single Mode 9/125 Micron.

2.2.1 Generator to DEV – DNP Serial Read Data Exchange Connection

The connection labeled "Generator to DEV - DNP Serial Read Data Exchange" in Figure 1 will contain all "read data" from the generation facility that is required by PJM, DEV SOC, DEV MOC, DE DEGM, and site personnel at the GI substation. No control commands are to be sent over this link due to the high data volume and throughput restrictions of using DNP Serial. The universal DNP map for this link is defined in an Excel spreadsheet that is available upon request. There are separate versions of this document used for solar and wind generation facilities. Section 3.2.1 details the specific data exchange requirements for the data points in the document. The required serial settings for this link are 19200 Baud, 8 Data Bits, No Parity, 1 Stop Bit. DNP client address 100, DNP server address 1. The GI RTAC is the DNP client device and the Site RTU/PPC/RTAC is the DNP server for this link. This connection will be required in all scenarios regardless of site type, configuration, and operational agreement with Dominion Energy.

2.2.2 Generator to DEV – DNP Serial Control Data Exchange Connection

The connection labeled "Generator to DEV - DNP Serial Control Data Exchange" in Figure 1 will contain all control commands and their associated feedback points from the generation facility that is required by PJM, DEV SOC, DEV MOC, DE DEGM at the GI substation. The separate control link is specified to eliminate latency and throughput concerns that may come about on a higher data volume serial data link. The universal DNP map for this link is defined in an Excel spreadsheet that is available upon request. Section 3.2.2 details the specific data exchange requirements for the data control points included in the document. The required serial settings for this link are 19200 Baud, 8 Data Bits, No Parity, 1 Stop Bit. DNP client address 100, DNP server address 2. The GI RTAC is the client and the Site RTU/PPC/RTAC is the server for this link. This connection will only be required where DNP control exchanges need to occur between the two facilities.

2.2.3 DEV to Generator – DNP Serial Data Exchange Connection

The connection labeled "DEV to Generator- DNP Serial Data Exchange" in Figure 1 will contain all GI substation read data to be provided to the generation facility for operational awareness and data historization. The universal DNP map for this link is defined in an Excel spreadsheet that is available upon request. Section 3.2.3 details the specific categories and characteristics of this data required under various circumstances. The required serial settings for this link are 19200 Baud, 8 Data Bits, No Parity, 1 Stop Bit. DNP Client Address 100, DNP Server Address 1. The Site RTU/PPC/RTAC is the Client, and the GI RTAC is the Server for this link. This connection will be required in all scenarios regardless of site type, configuration, and operational agreement with Dominion Energy.

2.2.4 DE Sub-Metering RTU Serial Link

The connection labeled "DE Meter RTAC to DEV GI RTAC - DNP Serial Meter Real Time Data" in Figure 1 will contain all real time metering data and associated communication status of all Dominion Energy owned sub-metering on premises at the generator collector substation. No further details regarding data specification are needed since this connection will be internal between two DEV owned RTUs. This connection will only be required in circumstances where Dominion Energy MOC/DEGM has entered a PPA with the generation facility and is only purchasing a portion of the total power output of the plant, thus necessitating additional DEV-Owned sub-metering to be installed on premises at the generator collector substation. Extension of the GI substation network to support remote access to this equipment is prohibited by DE cyber security requirements.

3 DATA EXCHANGE REQUIREMENTS

Data exchange between the two facilities is specified via data models for each connection depicted in Figure 1. These data models are defined by a set of universal DNP data exchange point maps. Section 3.1 defines the attributes of these point maps and how to apply them at each site. Section 3.2 and its subsections detail the data exchange requirements for each of the connections defined in section 2.2.1-2.2.3. For the connections defined in sections 2.2.1 and 2.2.2, the customer is required to use the associated universal documentation template, fill out site-specific details, mark available points, define point sources, and provide the documentation to Dominion Energy to be used by Data Communication Engineering. For the connection defined in section 2.2.3, Dominion Energy Data Communications Engineering is required to use the associated universal documentation template, fill out site-specific details, mark available points, define point sources, and provide the documentation to the customer.

3.1 Universal DNP Data Exchange Documentation

The universal data exchange spreadsheets contain a superset list of all possible points required in the data exchanges between the two facilities. While every attempt has been made to proactively predict the data exchanges needed into the future, the very nature of renewable generation and its rapid advancements will likely require that the exact data exchange requirements will continue to evolve. These data exchanges are meant to be tools to speed development time and reduce custom engineering and programming from site to site.

There may be cases where the exact needs of the site fall outside of the parameters defined by the universal maps. In these cases, the customer will need to work with Data Communications Engineering at Dominion Energy to work through the details that deviate from the standard and develop custom modifications to meet the needs of the site.

In practice, the data needs from site to site are relatively stable, where the only variables are typically the number of GSUs, Breakers, Inverters, Meters, Wind Turbines, Meteorological Stations, etc. Data points defining parameters for these common attributes of the generation facility appear at rigidly defined DNP addresses. Evolutions in the data exchanges will occur in such a way that previously defined standard points will remain at their original DNP addresses and newer points appearing in the standard will be appended to the end of the map to avoid "point shifts" and reduce potential errors. Due to project timing between when sites enter the

PJM queue and actual construction, exact revision numbers for these documents will not be specified by the FIR. The customer and Dominion Energy project teams must coordinate which map revision they are working from and work from the most recent revision at the time of construction.

There may be cases where the existing generator interconnection at a GI station followed data requirements from a legacy data standard while the new interconnection being added to the station is following the most recent data standard. The expectation is that the new interconnection must follow the latest standard. This is an inevitable consequence of the progression of data exchange requirements over time.

3.2 Data Exchange Requirements Per Serial Link

The following sections detail the data exchange requirements for the each serial link defined in sections 2.2.1-2.2.3. These are to be treated as minimum requirements, the requirements for a given site may not be limited to what is defined below. Please also note that for traditional generation facilities like fossil/hydro/nuclear plants, the data exchange requirements will need to be considered on a case-by-case basis due the widely varying configuration and design of these facilities, and how infrequently these types of generators interconnect to the system in recent years. The data exchange requirements contained in the following section primarily pertain to solar, wind, and battery storage facilities.

3.2.1 Generator to DEV – “Read Data” Data Exchange Requirements

The data exchange requirements for the read data link are categorically defined below. The categories align with the entries in the Sections column in the universal documentation template. Please note that there are separate versions of the “Read Data” documentation for solar and wind.

High-side Breakers: The customer is to provide the status and the breaker failure lockout indication for each transmission breaker on the high-side of each GSU. The phase-phase voltage, phase-neutral voltage, per-phase current, and frequency and watt/var power measurements are to be provided from the protection relay associated with each breaker. The communications failure alarm for each breaker relay is to be provided. The customer is to identify from which relay each point is sourced.

Motor Operated Disconnects: The customer is to provide the status for each transmission voltage motor operated disconnect that serves as an electrical disconnect between the generation facility and the utility. If there are multiple MODs in series between the utility, as shown in Figure 2, the MOD electrically closest to the GI substation will be mapped to the first MOD status point, and the next to the second, etc.

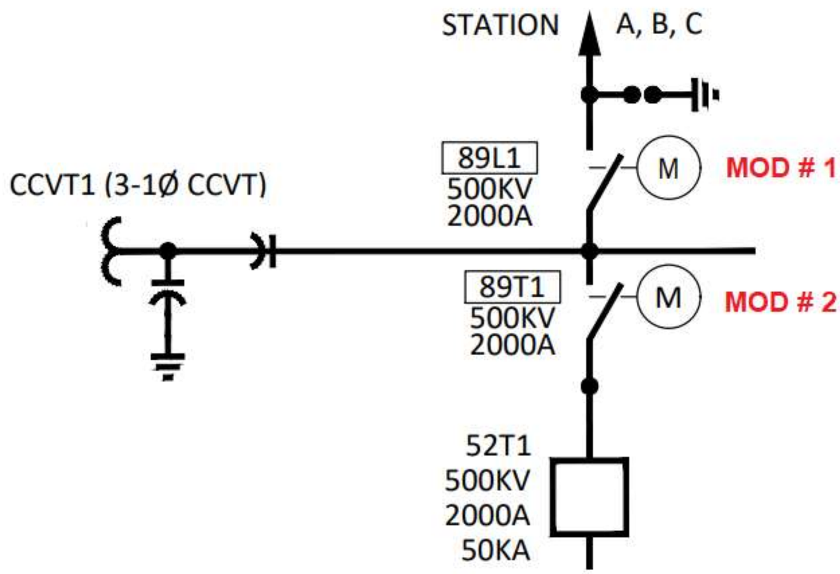

Figure 2: Example Series Motor Operated Disconnect Configuration

The customer is to identify which protection relay or I/O device this status is sourced from.

Feeder And Capacitor Bank Breakers: For the feeder and capacitor bank breakers on the medium voltage side of the GSU, the customer is to provide the status of each feeder and capacitor bank breaker. The phase-phase voltage, phase-neutral voltage, per-phase current, frequency, and watt/var power measurements are to be provided from the protection relay associated with each breaker. The communications failure alarm for each breaker relay is to be provided. The customer is to identify from which relay each point is sourced.

Transmission Line: Line differential protection is required between the two facilities. The following information is required from both differential relays: the month, day, year, hour, minute, second, millisecond, fault location, fault amps, and faulted phases (transmitted as a DNP binary input per faulted phase) for the four most recent fault records in the relay. The customer is to provide the phase-phase voltage, phase-neutral voltage, per-phase current, frequency, and watt/var power readings from each line relay. The customer is to provide the differential fiber channel failure alarm, the abnormal potential alarm, and line lockout indication from each relay. The communications failure alarm for each line relay is to be provided.

Site Control Meters: Generation facilities will have a variety of different metering configurations, to ensure complete information is supplied to Dominion Energy, the requirement for facility owned control, check, and sub-metering is as follows: The customer is to supply phase-phase voltage, phase-neutral voltage, per-phase current, frequency, and watt/var power from every substation meter at the site. The customer is to provide the communications failure alarm for each meter at the facility. The universal documentation has provisions for up to two high-side control meters, up to four low-side control meters per GSU with up to three GSUs, and up to two circuit sub-meters per feeder circuit, up to 12 circuits. These meters are referred to as the "PQM" meters in some contexts, as they are not the revenue meters of record for PJM. If the metering requirements at this facility fall outside of these options, the customer is to add the additional points to the end of the analog map, this change is to be coordinated with Data Communications Engineering.

Power Plant Controller/Park Pilot: The customer is to provide the operating state of the Real Power (MW) PID Control Program, the Voltage PID Control Program (commonly referred to as the "AVR"), the Reactive Power (MVAR) PID Control Program, and the Power Factor PID Control Program. If there is more than one PPC, with a maximum of three PPCs, a per-program status per PPC is required. The customer is to provide the present operating setpoint of each PID control program per PPC (MW/MVAR/Voltage/Power Factor).

Meteorological Station: PJM requires meteorological data for operational purposes [2]. The customer is to provide the global horizontal irradiance (GHI) measurements from every GHI sensor at every met station measured in watts per meters squared (solar only). The customer is to provide the plane of array (POA) measurements from every POA sensor at every met station measured in watts per meters squared (solar only). The customer is to provide the humidity measurements from every humidity sensor at every met station measured as a percentage (wind only). The customer is to provide the barometric pressure measurements from every pressure sensor at every met station, measured in units of hectoPascal (hPa) (wind only). The customer is to provide the ambient temperature readings from every ambient temperature sensor at every met station measured in degrees Fahrenheit (wind and solar). The customer is to provide the back of module (BOM) temperature readings from every BOM sensor at every met station measured in degrees Fahrenheit (solar only). The customer is to provide the wind speed readings from every wind speed sensor at every met station measured in meters per second (wind and solar). The customer is to provide the wind direction readings from every sensor at every met station measured in degrees from true north (wind and solar). The customer is to provide the communications failure alarm for every met station at the facility. The customer is to identify the site-specific name of each met station for reporting data issues to the future O&M provider.

PV Array (Solar Version Only): All inverters referenced in this section are associated with the PV array and are not related to battery storage; there is a separate section in the DNP map for battery storage information. The customer is to provide the inverter online status for each inverter or skid of inverters. If the inverters are a skid-based system with a system control unit (SCU), then the customer is to provide the number of inverters on that skid that are online. "Inverter online" is defined as the operational state where the inverter is grid-connected and is producing AC real power and can produce reactive power output if directed to do so by the PPC. The customer is to provide the inverter nighttime var online status for each inverter of a skid of inverters. If the inverters are a skid-based system with a system control unit (SCU), then the customer is to provide the number of inverters on that skid that are online in nighttime var mode. "Inverter Night Var Online" is defined as the operational state where the inverter is grid-connected and can produce only reactive power output if directed to do so by the PPC.

The customer is to provide the maximum allowed real power output capability of all inverters at the facility in the form of a DNP analog input point. This is maximum real power setpoint that the PPC is allowed to write to each inverter when controlling POI MW output. This value is typically the nameplate rating of the inverter but can sometimes be artificially curtailed to ensure site maximum power capacity is not exceeded at the POI. The customer is to provide the maximum lead/lag allowed reactive power output capability of all inverters at the facility in the form of two separate DNP analog input points. These two points are the maximum lead/lag reactive power setpoints that the PPC is allowed to write to each inverter when operating in the various Voltage/MVAR/Power Factor control modes.

The customer is to provide the real-time real and reactive AC power output of each inverter or skid of inverters. If the inverters are a skid-based system with a System Control Unit (SCU), the totalized watt/var readings from the SCU can be used; individual SCU sub-inverter real time power readings are not required. The customer is to provide the site-specific inverter name for the source device for each inverter point for reporting data issues to the future O&M provider. Communication failure alarms for each inverter do not need to be sent, a non-communicating inverter is to be considered offline, since it cannot be controlled by the PPC.

Wind Turbines (Wind Version Only) - The customer is to provide the turbine online status for each wind turbine. "Turbine online" is defined as the operational state where the wind turbine is grid-connected and can produce AC real power output if there is sufficient wind and can produce AC reactive power output if directed to do so by the PPC/Park Pilot. The customer is to provide the maximum allowed real power output capability of all wind turbines at the facility in the form of a DNP analog input point. This is the maximum real power setpoint that the PPC/Park Pilot is allowed to write to each wind turbine when controlling POI MW output. This value is typically the nameplate rating of the Turbine but can sometimes be artificially curtailed to ensure site maximum power capacity is not exceeded at the POI. The customer is to provide the maximum lead/lag allowed reactive power output capability of all wind turbines at the facility in the form of two separate DNP analog input points. These two points are the maximum lead/lag reactive power setpoints that the PPC/Park Pilot is allowed to write to each inverter when operating in the various Voltage/MVAR/Power Factor control modes.

The customer is to provide the real-time real and reactive AC power output of each wind turbine. The customer is to provide the site-specific wind turbine name for the source device for each turbine point for reporting data issues to the future O&M provider. Communication failure alarms for each Turbine do not need to be sent, a non-communicating turbine is to be considered offline, since it cannot be controlled by the PPC/Park Pilot.

Battery Storage (Solar or Wind Version) – The generation facility can be a stand-alone bulk electric storage system (BESS) or can be a solar or wind generation facility with incorporated battery storage. For a stand-alone BESS system, or a solar generation facility with incorporated battery storage, use the solar version of the documentation template. For a wind generation facility with incorporated battery storage, use the wind version of the documentation template. The customer is to provide the BESS operational state in the form of four separate DNP Binary

Input statuses: (Charging, Discharging, Standby, Off). “Standby” is defined as the operational state where the BESS is online but is currently in between charging and discharging cycles and is sitting idle. “Off” is defined as the operational state where BESS is not online and is not ready to perform a charge or discharge cycle. The customer is to provide the following quantities via DNP analog input points: BESS total MWH capacity, BESS stored MWH, BESS available MWH storage, BESS state of charge (“SOC” - expressed as a percentage), BESS maximum charge MW, BESS maximum discharge MW.

For individual BESS inverters, the customer is to provide an “inverter online” status. “Inverter online” for a BESS inverter is defined as the operational state where the inverter is grid-connected and is capable of provide positive or negative AC real power flow in support of charging and discharging the batteries, and in a state where it can provide AC reactive power if directed to do so by the BESS Controller/PPC/Park Pilot. The customer is to provide the real-time real and reactive AC power output of each BESS inverter. The customer is to provide the site-specific BESS inverter name for the source device for each inverter point for reporting data issues to the future O&M provider. Communication failure alarms for each BESS inverter do not need to be sent, a non-communicating inverter is to be considered offline, since it cannot be controlled by the PPC.

The customer is to provide the maximum allowed real power output capability of all battery storage inverters at the facility in the form of a DNP analog input point. This is maximum real power setpoint that the PPC is allowed to write to each inverter when controlling POI MW output. This value is typically the nameplate rating of the inverter but can sometimes be artificially curtailed to ensure site maximum power capacity is not exceeded at the POI. The customer is to provide the maximum lead/lag allowed reactive power output capability of all inverters at the facility in the form of two separate DNP analog input points. These two points are the maximum lead/lag reactive power setpoints that the PPC is allowed to write to each inverter when operating in the various Voltage/MVAR/Power Factor control modes.

A note on the BESS Controller and the Power Plant Controller: the BESS controller might be a separate control system from the PPC that controls the PV array/wind turbines or could be integrated into the PV/wind PPC as a hybrid resource. The customer is to identify the BESS controller in this documentation as one of the PPCs if it is a separate control system from the PV/wind PPC.

3.2.2 Generator to DEV – “Control Data” Data Exchange Requirements

The data exchange requirements for the control data link are specific to the power plant controllers. An important note on this section, this is only defining the technical requirements for each control data exchange, not the operational requirements for each control. The customer is required to provide these controls across the link; however, the usage of these controls will be dictated by operational agreements between the customer and Dominion Energy. If there are no operationally agreed upon controls that will be issued from the utility to the generator, then there is no need to have the serial control data link established.

Real Power (MW) Control: The customer is to provide a real power analog setpoint control per PPC, this will be the setpoint that the “Real Power (MW) PID Control Program” follows. There is a corresponding point in the DNP analog input map that serves as feedback that the PPC has received the updated setpoint. This feedback point is identical to the MW setpoint analog input specified in the “PPC/Park Pilot” requirements in section 3.2.1. The customer is to provide binary output controls that allow the “Real Power (MW) PID Control Program” to be enabled or disabled. There is a corresponding point in the DNP binary input map that serves as feedback that the PPC has been directed to change the operational mode of this program. This feedback point is identical to the operating state point specified in the “PPC/Park Pilot” requirements in section 3.2.1.

Voltage (AVR) Control: The customer is to provide a voltage analog setpoint control per PPC, this will be the setpoint that the “Voltage PID Control Program (AVR)” follows. There is a corresponding point in the DNP analog input map that serves as feedback that the PPC has received the updated setpoint. This feedback point is identical to the voltage setpoint analog input specified in the “PPC/Park Pilot” requirements in section 3.2.1. The customer is to provide binary output controls that allow the “Voltage PID Control Program (AVR)” to be enabled or disabled. There is a corresponding point in the DNP binary input map that serves as feedback that the PPC has been directed to change the operational mode of this program. This feedback point is identical to the operating state point specified in the “PPC/Park Pilot” requirements in section 3.2.1.

Reactive Power (MVAR) Control: The customer is to provide a reactive power analog setpoint control per PPC, this will be the setpoint that the “Reactive Power (MVAR) PID Control Program” follows. There is a corresponding point in the DNP analog input map that serves as feedback that the PPC has received the updated setpoint. This feedback point is identical to the MVAR setpoint analog input specified in the “PPC/Park Pilot” requirements in section 3.2.1. The customer is to provide binary output controls that allow the “Reactive Power (MVAR) PID Control Program” to be enabled or disabled. There is a corresponding point in the DNP binary input map that serves as feedback that the PPC has been directed to change the operational mode of this program. This feedback point is identical to the operating state point specified in the “PPC/Park Pilot” requirements in section 3.2.1.

Power Factor Control: The customer is to provide a power factor analog setpoint control per PPC, this will be the setpoint that the “Power Factor PID Control Program” follows. There is a corresponding point in the DNP analog input map that serves as feedback that the PPC has received the updated setpoint. This feedback point is identical to the power factor setpoint analog input specified in the “PPC/Park Pilot” requirements in section 3.2.1. The customer is to provide binary output controls that allow the “Power Factor PID Control Program” to be enabled or disabled. There is a corresponding point in the DNP binary input map that serves as feedback that the PPC has been directed to change the operational mode of this program. This feedback point is identical to the operating state point specified in the “PPC/Park Pilot” requirements in section 3.2.1.

Site Vs. Utility Control: The customer is to create logic in each PPC that establishes a site/local versus utility/remote control mode. When a PPC is in local or site mode, it will only follow locally issued commands (commands not issued from the utility). When a PPC is in remote or utility mode, for the controls that are operationally agreed upon to be issued by the utility, the PPC will only accept commands for those specific controls from the utility. The customer is to report the status of this control mode per PPC via the specified site/utility status points in the DNP binary input map.

3.2.3 DEV to Generator – DNP Serial Data Exchange Requirements

These are the data exchange requirements for the link where the generation facility can collect switchyard information from the GI substation. The provided documentation template for this link provides a superset of all data for a variety of GI configurations. Dominion Energy is to mark up this documentation and provide to the customer the data points that will be provided based on the site configuration.

Transmission Breakers: Dominion Energy is to provide to the customer the status of all breakers that directly connect the generation facility to the transmission network. The customer will be provided breaker failure lockout indications for each transmission breaker that can issue a transfer trip to the generation facility. The customer is to be provided the source device for each of these indications and a communications failure alarm for each source device.

Transmission Line: Line Differential protection is required between the two facilities. Dominion Energy is to provide the following information to the customer from both differential relays: The month, day, year, hour, minute, second, millisecond, fault location, fault amps, and faulted phases (transmitted as a DNP binary input per faulted phase) for the four most recent fault records in the relay. The customer is to be provided the phase-phase voltage, phase-neutral voltage, per-phase current, frequency, and watt/var power readings from each relay. The customer is to be provided the differential fiber channel failure alarm, the abnormal potential alarm, and line lockout indication from each relay. The communications failure alarm for each line relay is to be provided to the customer.

Islanding: Dominion Energy is to provide status that an anti-islanding transfer trip has been issued from the GI substation to the generation facility. The customer is also to be provided the communications failure alarm for the islanding protection relay that generates this indication.

POI Metering: There is a primary and backup revenue meter at the POI within the GI substation. These meters are referred to as the “RQM” meters in some contexts, as these are the revenue meters of record for PJM. These meters provide the “net” metering for the generation facility. Dominion Energy is to provide to the customer the following points from each meter: phase-phase voltage, phase-neutral voltage, per-phase current, three-phase average current, three-phase average voltage, frequency, and watt/var power readings. The customer is also to be provided received and delivered watt-hour and var-hour counters, presented in both an end-of-interval and continuously running format. “End-of-Interval” counters will report at the top of every hour the total watt-hours and var-hours measured for the entirety of the previous hour. The meters are time synchronized using a global positioning system (GPS) synchronized satellite clock. The usage of the continuously running counters will require the facility to perform their own precisely timed freeze, read, and time differential calculation to determine the total counts for the previous hour. Dominion Energy is to provide the communications failure alarms for each POI revenue meter.

SOC Voltage Control: The SOC voltage control SCADA application will generate alarms if the facility operates outside of the allowed voltage schedule voltage band. The voltage band upper and lower threshold values will be sent to the customer each as DNP analog input points. There will be an initial alarm marking the start of a 30-minute timer, and a second alarm marking that voltage at the POI has been out of band for more than 30 minutes. Section 5.1 expands further on this application.

4 CUSTOMER SITE DOCUMENTATION REQUIREMENTS TO DOMINION ENERGY

Dominion Energy needs to know the configuration and capabilities of the facility in order to integrate the site into the transmission network and for various operational and contractual arrangements. The customer is to provide the following documentation to Dominion Energy in support of data exchange between the facilities and EMS/GMS modeling activities.

- The AC protection single line diagram for the attached collector substation.
- The AC single line diagram for the PV array showing which inverters are connected to each feeder circuit (if solar).
- The AC single line diagram for the wind turbines showing which wind turbines are connected to each feeder circuit (if wind).
- The AC single line diagram for a BESS showing which battery inverters are connected to each feeder circuit.
- The Continuous Unit Reactive Capability Curve or “D-Curve” for the faciltiy. If there is more than one unit, this must be expressed per unit. A unit is defined per PPC.
- The generation facility nameplate real power and reactive capabilities, as in the maximum MW and MVAR output capability of the plant at the POI.
- The details of all meteorological stations, detailing the total number of met stations, the attached sensors and available measurements at each station. A single representative example can be provided if all stations are identical. Identify the site-specific name of each met station.
- For solar- the per-inverter watt/var maximum capability.If the inverters are skid based, identify the per-skid watt/var maximum capability. If the number of inverters varies per skid, this will need to be broken down on a skid-by-skid basis. Identify if the inverters maximum var capability differs when utilized for nighttime var support, and the actual maximum var capability.

- For wind- the per turbine watt/var maximum capability. Identify which turbines (if any) support no-load reactive power support and the maximum var capability when the turbine in operating in no-load reactive support (if it differs from the value while generating).
- For battery storage- the per-BESS inverter watt/var maximum capability, the total BESS storage capacity, and the maximum charge/discharge rating for the system.

5 COMMON SCADA APPLICATION CONTROL NARRATIVES

There may be a wide variety of SCADA control schemes deployed from site to site, however some will be common to all or most sites, these are discussed below.

5.1 SOC Voltage Control

Each PPC is to follow a voltage setpoint signal issued from the Dominion Energy System Operations Center (SOC). The setpoint is issued through the GI Substation via the GI RTAC Generator to DEV – “Control Data” serial link and via the voltage setpoint controls per PPC in that link (as described in section 3.2.2). This setpoint will electronically transmit the voltage schedule from the transmission operator. The setpoint is setting the voltage setpoint in the “Voltage PID Control Program (AVR)” per-PPC as referenced throughout the section 3 data exchange requirements. The GI RTAC will monitor the setpoint versus the measured voltage at the POI, if the voltage deviates outside of the allowed band, an alarm will be generated to the generation facility across DEV to Generator read data link as described in section 3.2.3. The upper and lower bounds of this voltage band will be provided as DNP analog inputs to the customer across the DEV to Generator read data link as described in section 3.2.3. The initial alarm indicates to both parties that since the generator has fallen outside of the allowed voltage band, that there has been a “status change” in the AVR functionality of the site, according to requirement R3 of the NERC VAR-002-4 standard [3]. This alarm also marks the start of a 30 minute timer. If the voltage continues to stay out of band for more than 30 minutes, a second alarm will trigger for both the generator and the SOC. Please note that the generator operator is still required to alert the transmision operator (the SOC) when this 30 minute threshold is crossed as per the NERC VAR-002-4 standard [3].

If the generation facility is a solar generation site, the voltage setpoint is to be followed as the site inverters seamlessly transition from daytime generation to nighttime var-only reactive support. Similarly if the generation facility is a solar generation site, the voltage setpoint is to be followed as the inverters seamlessly transition from nighttime var-only support to daytime generation.

The setpoint is to be issued from the SOC when a change is required. The PPC is to hold the setpoint static until a different setpoint is issued from the SOC. The PPC will only accept a voltage setpoint if the unit is running with its AVR enabled and if the site/utility control mode is running in utility control mode.

The PPC is to reject any voltage setpoint received that is outside the operational band of the voltage schedule.

5.2 MOC/DEGM-PJM Curtailment

Under certain operational arrangements the Dominion MOC/DEGM will need to issue a PJM Curtailment MW setpoint to the PPC. The setpoint is issued through the GI Substation via the GI RTAC Control link and via the real power setpoint controls. This setpoint will electronically transmit the unit requested real power output from the MOC or DEGM. The setpoint is setting the real power setpoint in the “Real Power (MW) PID Control Program” for the given PPC as referenced throughout the section 3 data exchange requirements.

The setpoint is to be issued from the MOC/DEGM on a continuous regular update cycle, typically every 4 seconds, akin to a traditional generation AGC signal. The PPC is to hold the setpoint static until a different setpoint is issued from the MOC/DEGM. The PPC will only accept a real power setpoint if the unit is running with its MW control mode enabled and if the site/utility control mode is running in utility control mode.

The PPC is to reject any real power setpoint received that is outside the operational parameters of the site interconnection agreement (IA).

6 CONSTRUCTION PROJECT MILESTONES AND DOMINION ENERGY SOC SCADA REQUIREMENTS

Certain SCADA requirements must be met before the Dominion Energy SOC will allow the generation facility to back-feed and reach first-sync and start generating power to the grid. There are also SCADA tests that must be performed once the site is fully commissioned prior to substantial completion, these are detailed in the following sections. Please note that the following requirements pertain to solar/wind/battery storage facilities. SOC SCADA requirements for a traditional fossil/hydro/nuclear generation facility will be evaluated on a case-by-case basis and communicated to the customer.

6.1 Back Feed

For the generation facility to back feed and start receiving off-site power from the transmission network the following SOC SCADA requirements must be met:

- The SOC must have visibility of generation facility high side breaker status, breaker failure and transmission voltage motor operated disconnect (MOD) status points. These are provided by the customer to Dominion via the “Generator to DEV – Read Data” link as specified in section 3.2.1.
- The SOC must have visibility of the voltage readings from the transmission voltage CCVT at generation facility. These readings are sourced from high side breaker failure relays, line relays, and high side control meters. These are provided by the customer to Dominion via the “Generator to DEV – Read Data” link as specified in section 3.2.1.
- The SOC must have visibility of the POI revenue metering data. This is provided by Dominion Energy to the Dominion SOC.

6.2 Generation First Sync

For the generation facility to first sync and start producing power to the transmission network, the following SOC SCADA requirements must be met:

- The SOC must have visibility to the low side “gross” real and reactive power readings. These readings either come from the summation of metering data from medium voltage feeder breaker/cap bank breaker protection relays, from per-circuit sub-meters, or GSU low-side control meters.
- The SOC must have visibility to the low side “gross” real and reactive power readings. These readings either come from the summation of metering data from medium voltage feeder breaker/cap bank breaker protection relays, from per-circuit sub-meters, or GSU low-side control meters.
- The SOC must have modeled the generation units as per the site D-curve and nameplate characteristics into EMS system and state-estimator. The EMS modeling team requires the documentation as specified in section 4 to complete this task.
- All per-PPC AVR (“Voltage PID Control Program” enable/disable) status points must be SCADA checked from the PPC to the SOC.

6.3 Site Substantial Completion

Frequently the full site is not yet commissioned as of the first sync date, so some finalized testing must wait for full site commissioning to occur. Prior to site substantial completion, the SOC voltage control SCADA application must be tested and verified, as well as other remaining SCADA checks that could not be completed at the time of First Sync. The following verifications must be performed:

- The SOC voltage control application must be tested and verified such that the site accepts and follows a voltage setpoint issued from the SOC.
- The upper and lower bounds of the voltage application must be tested and rejection of unreasonable voltage setpoints must be verified.
- The site/utility control mode functionality must be verified. The site must reject commands if in site mode and accept agreed upon commands if in utility mode.
- If a solar facility, the transition of daytime generation to nighttime AVR support for the voltage control application must be verified. Likewise- the transition from nighttime AVR support to daytime generation AVR support must be verified.
- All PV array/turbine/battery storage/met station SCADA read data is to be verified once full site commissioning is completed.

7 BIBLIOGRAPHY

[1] "Facility Interconnection Requirements," Dominion Energy, most recent version.

[2] *PJM Manual 14D: Generator Operational Requirements,* PJM, Revision 62, 2022

[3] *VAR-002-4 Generator Operation for Maintaining Network Voltage Schedules,* North American Electric Reliablity Coporation, 2014.

8 REVISION HISTORY

Revision Date	Revision #	Description	Revised By	Effective Date
3/10/2023	0.0	Document Creation	Daniel Camp	4/1/2023
11/15/2023	1.0	Reviewed and Updated	Jason Lettieri	1/1/2024