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## Dominion Energy Virginia—Electric Transmission Facility Interconnection Requirements


Revision Coordinator	Signature	Date
Thomas McConnell Consulting Engineer Electric Transmission Planning	Signature on File	3/16/2026

Compliance Reviewer	Signature	Date
Robert Gillis NERC Compliance Program Manager ET NERC Regulatory Compliance	Signature on File	3/16/2026

Approved By Name and Title	Signature	Date Approved
Keith Graham Manager Electric Transmission Planning	Signature on File	03/16/2026
Jonathan Deverick Manager Electric Transmission Planning	Signature on File	03/17/2026
Jacki Vitiello Director Electric Transmission Planning	Signature on File	03/16/2026
Katelynn Vance Manager Electric Transmission Strategic Initiatives	Signature on File	03/16/2026
Kyle Hannah Senior Director Electric Transmission Strategic Initiatives	Signature on File	03/19/2026
Brandon Patterson Manager, Electric Transmission Engineering Standards	Signature on File	03/19/2026
Micah Till Manager, Electric Transmission System Protection Engineering	Signature on File	03/20/2026
Brian Starling Director, Electric Transmission Operations Engineering and Reliability	Signature on File	03/16/2026
Nancy Ashberry Director, Electric Transmission NERC Regulatory Compliance	Signature on File	03/16/2026
Matthew Parker Director, Electric Transmission System Operations Center	Signature on File	03/17/2026

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**Facility Interconnection Requirements Supporting Documents**

- Attachment 1—Electric Transmission Planning Criteria (Rev 26.0)
- Attachment 2—Customer Delivery Point Request (Revision 4.0)
- Attachment 3—Generator Interconnection Protection Requirements (Rev 7.0)
- Attachment 4—Ride-Through Requirements for Bulk Power System Generators (Rev 5.0)
- Attachment 5—Generator Interconnection Data Communications and Data Exchange Requirements (Rev 2.0)

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Attachment 6—Technical Requirements for Generation Interconnection Substations (Rev 12.0)

Attachment 7—Modeling Requirements for Inverter-based Resources (IBRs) (Rev 2.0)

Attachment 8—Large Load Interconnection Requirements (Rev 2.0)



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### ABBREVIATIONS AND ACRONYMS

Term	Definition
<b>ANSI</b>	American National Standards Institute
<b>AVR</b>	Automatic Voltage Regulator
<b>BA</b>	Balancing Authority
<b>BES</b>	Bulk Electric System
<b>BIL</b>	Basic Lightning Impulse Insulation Levels
<b>BTM</b>	Behind-the-meter
<b>CMCP</b>	Configuration Management & Control Program
<b>CMP</b>	Configuration Management Program
<b>CT</b>	Current Transformer
<b>DAS</b>	Data Acquisition System
<b>DEV-ET</b>	Dominion Energy Virginia Electric Transmission
<b>DR</b>	Design Requirement
<b>EHV</b>	Extra-high Voltage
<b>EMT</b>	Electromagnetic transient
<b>ERAG</b>	Eastern Interconnection Reliability Assessment Group
<b>ESC</b>	Enter Service Commissioning
<b>FIR</b>	Facility Interconnection Requirements
<b>FIV</b>	Field Inspections & Verifications
<b>FRM</b>	Facility Rating Methodology
<b>GIA</b>	Generation Interconnection Agreement
<b>GIS</b>	Gas-insulated Substation
<b>IBR</b>	Inverter-based Resource
<b>IEC</b>	International Electrotechnical Commission
<b>IEEE</b>	Institute of Electrical and Electronics Engineers
<b>ISA</b>	Interconnection Service Agreement
<b>LLDB</b>	Live Line, Dead Bus
<b>MAC</b>	Minimum Acceptance Criteria
<b>MMWG</b>	Multi-regional Modeling Working Group
<b>MOA</b>	Mutual Operating Agreement
<b>MOAB</b>	Motor-operated Air Breaker
<b>NDA</b>	Nondisclosure Agreement
<b>NERC</b>	North American Electric Reliability Corporation
<b>NESC</b>	National Electricity Safety Code
<b>NEMA</b>	National Electrical Manufacturers Association
<b>NUG</b>	Non-utility Generator
<b>OATT</b>	PJM Open Access Transmission Tariff
<b>OEM</b>	Original Equipment Manufacturer
<b>OSHA</b>	Occupational Safety and Health Administration
<b>PCC</b>	Point of Common Coupling
<b>PEILL</b>	Power Electronic Interface Large Loads

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<b>Term</b>	<b>Definition</b>
<b>POI</b>	Point of Interconnection
<b>PPC</b>	Power Plant Controller
<b>QAE</b>	Quality Assurance Engineer
<b>QAP</b>	Quality Assurance Program
<b>RC</b>	Reliability Coordinator
<b>RF</b>	Rating Factor
<b>RMS</b>	Root-mean-squared
<b>RTO</b>	Regional Transmission Organization
<b>RTU</b>	Remote Terminal Unit
<b>SCADA</b>	Supervisory Control and Data Acquisition
<b>SER</b>	SERC East-RFC
<b>SERC</b>	SERC Reliability Corporation
<b>SIR</b>	Source Impedance Ratio
<b>SIS</b>	System Impact Study
<b>SR</b>	Site Review
<b>TDD</b>	Total Demand Distortion
<b>THD</b>	Total Harmonic Distortion
<b>TOP</b>	Transmission Operator
<b>UCSA</b>	Upgrade Construction Service Agreement
<b>UDM</b>	User-Defined Model
<b>UTC</b>	Universal Time Coordination
<b>VT</b>	Voltage Transformer
<b>WTP</b>	Witness Testing Program

## DEFINITIONS

Words starting with a capital letter are considered defined terms. Defined terms are terms with a specific, agreed-upon meaning. Definitions for these terms are found in the NERC glossary of terms, the PJM OATT, and the table below.

<b>Term</b>	<b>Definition</b>
<b>Capacity</b>	Seasonal maximum generating capability of a generation Interconnection Customer’s Facility, measured in megawatts.
<b>Customer</b>	Interconnection Facility owner or requester who will apply for a new interconnection or change to an existing interconnection.
<b>Distribution Facilities</b>	Facilities rated at less than 69 kV that are owned and operated by the Company and are necessary to connect the Interconnection Customer’s Facility to the Transmission System.
<b>Emergency Condition(s)</b>	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



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Term	Definition
	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.
<b>Facility</b>	A set of electrical equipment that operates as a single bulk electric system Element (e.g., a line, a generator, a shunt compensator, a transformer, etc.).
<b>Good Utility Practice</b>	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 limited to the optimum practice, method, or act to the exclusion of all others but is intended to include acceptable practices, methods, or acts generally accepted in the region.
<b>Governmental Authority</b>	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.
<b>Interconnection Facilities</b>	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-ET System.
<b>Interconnection Customer</b>	A transmission, generation, or end user connected to, or seeking to connect to, the DEV-ET System.
<b>Interconnection Point</b>	The point at which the Facilities are physically connected to the Transmission System (including any Distribution Facilities required to facilitate the interconnection).
<b>Inverter-based Resource</b>	A non-synchronous generator that supplies power to the system using inverter technology.
<b>Metering Equipment</b>	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.
<b>RTO</b>	A Regional Transmission Organization or any successor thereof becomes responsible for operating the Company Transmission System to which the Interconnection Customer’s Facility is connected. PJM Interconnection, LLC is DEV-ET’s RTO.
<b>Transmission Element</b>	Transmission Elements are primary equipment (69 kV and above) that constitute or interconnect with the DEV-ET System. Examples include buses, lines, or transformers with a low-side voltage of 69 kV or above, regardless of BES status.
<b>Transmission System</b>	The Facilities owned by DEV-ET 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).
<b>Wholesale Distribution Service</b>	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.

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## 1.0 INTERCONNECTION STUDIES

Planning for transmission interconnections ensures that the Transmission System can continue to support power transfers between utilities, including firm transactions, following a fault or failure, which forces the removal of a generator, load, and/or Transmission Element from service.

To ensure that the DEV-ET system continues to meet its operational objectives, DEV-ET performs studies to evaluate existing interconnections seeking to make a qualified change as defined by the Planning Coordinator (PC). The Planning Coordinator, PJM, defines qualified change in PJM Manual 14b, Section G.12 NERC Standard FAC-002–Facility Interconnection Studies. These changes may come in the form of a new interconnection or changes to an existing interconnection. When complete, studies are reviewed to determine the impact a new interconnection or change may have on the DEV-ET system or the surrounding system.

### 1.1 Procedure for Coordinating New Interconnection Studies

Should DEV-ET receive an interconnection request or a Qualified Change request to an existing interconnection defined by the Planning Coordinator, which may impact a neighboring Transmission System, DEV-ET will initiate contact with the affected system or systems to coordinate joint interconnection studies.

DEV-ET is a member of PJM, and PJM is the Regional Transmission Organization (RTO) responsible for the reliability of the affected systems. The joint interconnection studies between neighbors are performed in coordination with PJM. In this way, PJM is notified of the changes created by the interconnection request.

### 1.2 Procedure for Notifying Those Responsible for Reliability


New interconnection projects and Qualified Changes to an existing interconnection are communicated to those responsible for the reliability of affected systems by participation in regional and subregional working groups and committees. Through the study process, parties responsible for reliability are notified of new interconnections or Qualified Changes to an existing interconnection. DEV-ET has entered into Inter-area Reliability Agreements with neighboring utilities and participates in the coordinated planning and operation activities with the groups listed here:

- 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 group has Working Groups, Study Groups, Committees, and Task Forces that deal with various aspects of power system reliability and security. These groups perform studies to assess the system’s reliability at the interconnection level. When complete, study results are presented to the appropriate group for review. The results identify system deficiencies and create corrective action plans when needed.

### 1.3 Procedure for Confirming Facility Location within the Balancing Authority

PJM Compliance Bulletin CB028 (NERC Standard FAC-001) specifies that PJM assesses Facilities within its Balancing Authority (BA) area, and any interconnection Customer seeking to connect new Facilities or upgrade existing Facilities within the PJM system must follow the PJM interconnection process. As part of this process, external entities engaging PJM for interconnection opportunities result in draft agreements being provided to DEV-ET for review and comment. Finalization occurs upon signature by the Interconnection Customer (or

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Project Developer), DEV-ET, and PJM. Approved projects receive an Interconnection Service Agreement (ISA), Upgrade Construction Service Agreement (UCSA), or Generation Interconnection Agreement (GIA), which are submitted to FERC for review and approval. Once approved, PJM files the ISA/UCSA/GIA and provides a copy to DEV-ET, with agreements also accessible via the PJM “Planning” website under “Service Request Status.” The presence of a PJM-issued ISA, UCSA, or GIA serves as formal confirmation that the facility is within the PJM BA area.

#### **1.4 Wholesale Delivery Points**

DEV-ET provides transmission service to wholesale delivery points throughout its service area under Mutual Operating Agreements (MOA). The criteria for serving wholesale Interconnection Customers are the same as those used to serve DEV-ET’s other Customers. The criteria are based on Good Utility Practices, sound engineering judgment, and economic principles without regard for the ownership of Interconnection Facilities.

Regardless of the generation source, all power supplied to wholesale Customers is delivered over the company’s transmission Facilities to the wholesale Customer. Therefore, the company’s planning must include wholesale Interconnection Customer load requirements.


DEV-ET and its wholesale Interconnection Customers will conduct joint planning studies periodically. The following criteria apply to all joint planning studies:

- 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, apply to the connection of any wholesale Interconnection Customer to DEV-ET’s Transmission System.
- The joint planning study would begin with a review of each company’s construction plans based on the company’s annually updated load forecasts for the area. The study scope will include the following:
  - The wholesale Interconnection Customers will prepare a load forecast for each year of the next ten years for their area.
  - DEV-ET will prepare load forecasts for the area around the Interconnection Customer.
  - For both conventional and alternative (solar, wind, etc.), distributed generation supplies the maximum output of each unit/site, the coincident output of each unit/site for the summer peak day, and the winter peak day for the DOM zone.
  - The Interconnection Customer and DEV-ET will each prepare preliminary studies of their respective systems to meet the future load requirements identified by the forecasts.
  - The Interconnection Customer and DEV-ET will exchange study information and prepare a long-range plan based on joint analysis.

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, DEV-ET and, if needed, entities interconnected to DEV-ET Facilities will expedite a review of appropriate Elements of the long-range plan to address such projects.

## **2.0 FACILITY INTERCONNECTIONS OR QUALIFIED CHANGE INTERCONNECTIONS**

When a Customer wishes to install, make a Qualified Change to an existing interconnection, or remove DEV-ET Facilities at a Delivery Point or Point of Interconnection (POI), the Customer must initiate the request in writing using the Customer Delivery Point Request in Attachment 2 of this document or through the processes

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outlined by the PJM Manual 14A and 14H to submit the request and Manual 14 series for additional steps and information. Note that the Customer must submit a Customer Delivery Point Request to DEV-ET when making Qualified Changes to the Customer’s Facilities that are anticipated to (i) lead to a qualified change to DEV-ET’s Facilities or (ii) impact the operation of DEV-ET’s Facilities. For load interconnections, Customers are required to submit the Customer Delivery Point Request directly to DEV-ET, ensuring Planning is formally notified. For generation interconnections, Customers must proceed through the PJM interconnection process as specified in the PJM Manual 14 series.

The procedures for coordinated studies of new interconnections or Qualified Changes to existing interconnections can be found in Attachment 1, Sections 2.5 and 3, and the PJM Manual 14 series. Section 1 above identifies the notification and confirmation procedures with the affected system(s).

**2.1 Required Simulation Data**


All changes to DEV-ET’s Transmission System affect the system’s behavior. This includes new interconnections and qualified changes to existing interconnections. As such, DEV-ET will perform studies to assess the Transmission System’s performance with the change and to determine if the change introduces any adverse impacts.

DEV-ET maintains a model of the existing system. At the time of the interconnection request, customers shall supply a steady-state power flow model. After Decision Point 2 of the PJM Queue Process, the developer shall provide a generic positive sequence (fundamental frequency) transient stability dynamic model and short-circuit model. After Decision Point 3 of the PJM Queue Process, the developer shall provide a positive sequence User Defined Model (UDM) and electromagnetic transient (EMT) model. When Qualified Changes to an existing interconnection are proposed, DEV-ET will require customers to supply updated models that reflect the Qualified Change. DEV-ET will require developers and owners to supply a steady-state power flow model, a positive sequence (fundamental frequency) transient stability dynamic model, an EMT model, and a short-circuit model of the Qualified Change to an existing interconnection they are sponsoring. EMT models are needed to assess the system’s response to transients, evaluate the behavior of Inverter-based Resources (IBR) during and after system events, and determine the effect large industrial loads may have on power quality. EMT simulations also investigate harmonics,<sup>1</sup> determine proper protection system settings, and evaluate IBR control settings.

Studies of the DEV-ET system are not a one-time occurrence. As part of DEV-ET’s reliability obligation, DEV-ET will continue to perform studies of its systems with models provided by the Interconnection Customer. Customer-submitted models must accurately reflect the as-built characteristics of the site and satisfy minimum benchmarking requirements, including comparing the response of all required models to specific disturbances. For model benchmarking, refer to PJM Dynamic Model Development Guidelines for Interconnection Analysis, Section 7: PJM Model Testing Requirements. Additionally, all IBRs must comply with the requirements specified in Attachment 7 of the Facility Interconnection Requirements (FIR). The Customer must ensure that the positive sequence and EMT models reasonably match each other in simulated behavior and parameterization. Customers should use engineering judgment and Pass/Fail criteria (as specified in Attachment 7) to verify that the models exhibit a reasonable dynamic response. Customers can direct

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<sup>1</sup> IEEE Std 3002.8-2018, “IEEE Recommended Practice for Conducting Harmonic Studies and Analysis of Industrial and Commercial Power Systems”.

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questions or concerns through the designated DEV-ET Project Manager or the alternate designated DEV-ET point of contact.

After construction is complete, as part of the commissioning process, it is the responsibility of the project owner to supply DEV-ET with up-to-date models to reflect the as-built system. Following that, validated models should be supplied as part of the NERC MOD-26 and MOD-27 compliance requirements; validation against field data is to be performed both for positive sequence and EMT models. During commercial operation, project owners are required to provide updated models following any qualified change to an existing interconnection or when requested by DEV-ET. The models must be delivered to DEV-ET in electronic format. They must be accompanied by an attestation stating that the models conform to all requirements and accurately represent the Customer’s Facility. Information requested by or provided to DEV-ET outside of the Customer Request process should be provided through the designated DEV-ET Project Manager or the alternate designated DEV-ET point of contact.

For Delivery point requests, the Customer must submit the “Customer Delivery Point Request,” detailed in Attachment 2, as soon as useful information is available. The Customer must submit a revised Request Form as additional information becomes available.

**2.2 Voltage Level and MW and MVAR Capacity or Demand at the POI**

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 Delivery Point Request,” detailed in Attachment 2, to provide DEV-ET with the necessary information regarding the voltage level and MW and MVAR Capacity or demand at the 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.

**2.3 Breaker Duty and Surge Protection**

High-voltage circuit breakers are subjected to continuous current. As such, the circuit breakers selected must be able to carry the maximum continuous currents found by load flow analysis. If the load flow analysis shows that the current flowing through a circuit breaker exceeds its “nameplate” or “normal” design capabilities, then the circuit breaker may only be used when allowed by a manufacturer’s design documentation or standard industry practices. Otherwise, a larger circuit breaker must be used, or some other design change must be made to limit the amount of short-circuit current.

High-voltage circuit breakers are to be designed to interrupt continuous and short-circuit current. Therefore, the circuit breakers selected must be able to interrupt the worst-case short-circuit current calculated using engineering software.

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 determined by lightning and switching surge analysis and the latest IEEE C62 standards.

Electrical equipment, including high voltage substation buses, must meet or exceed DEV-ET’s standard Basic Lightning Impulse Insulation Levels (BIL)<sup>2</sup> listed in the table below.

**Table 1. BIL: Electrical Equipment**

Equipment and Bus Nominal Voltage Rating (Phase-to-phase) kV, rms	BIL (Phase-to-ground) kV, crest
115	550
138	650
230	900
500	1,550

The Interconnection Customer must meet the following requirements:

- The Interconnection Customer is responsible for designing equipment to meet the short-circuit capabilities of their Facilities.
- The Interconnection Customer is responsible for specifying the ratings of their interrupting devices.
- The Interconnection Customer will provide existing and future fault current levels when requested.
- The Interconnection Customer is responsible for installing adequately rated interrupting devices at the POI for transmission-level delivery points. These devices must sufficiently protect the Customer’s equipment and ensure proper fault isolation.
- It is the responsibility of the Interconnection Customer to notify DEV-ET of any Qualified Changes to an existing interconnection that may cause an increase in fault currents (generator and transmission Interconnection Customers), using the procedures outlined in Section 2.0.
- For IBRs connecting to the DEV-ET system, the Interconnection Customer is responsible for ensuring that the isolation device used to isolate an IBR plant from the DEV-ET system follows IEEE Std 2800-2022.

## 2.4 System Protection and Coordination


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 protecting the Interconnection Customer’s equipment and other electrical assets.

The Interconnection Customer is responsible for providing a properly designed and tested Protection System to coordinate with the DEV-ET Protection Systems. Before designing its Protection Systems and establishing the protection settings, the Interconnection Customer should complete all the appropriate studies to ensure a sound design. These studies may include, but are not limited to, protection coordination studies, grounding studies, short-circuit studies, stability studies, and power quality studies.

Once complete, the study results will be available to DEV-ET for their assessment and agreement.

Using simulation software (ASPEN OneLiner, PSCAD, PSS/E), DEV-ET will confirm that the Interconnection Customer’s protection system design and settings are properly coordinated with DEV-ET’s protection systems. The Interconnection Customer must provide the models required for the simulations performed by DEV-ET.

<sup>2</sup> IEEE Std C62.82.1 - 2010, IEEE Standard for Insulation Coordination – Definitions, Principles, and Rules.

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When a simulation shows that the Interconnection Customer’s protection system does not coordinate with DEV-ET’s protection system, the Interconnection Customer will work with DEV-ET to make the changes necessary to coordinate the Interconnection Customer’s protection system with DEV-ET’s protection system.

Good Utility Practice dictates that the Protection Systems installed by the Interconnection Customer follow the latest IEEE C37 and IEEE C57 guides and standards for protective relaying systems and adhere to NERC and PJM standards related to system protection.

For information on generator interconnection, see Attachment 3—DEV-Generator Interconnection Protection Requirements.

### 2.4.1 Protection System Design

The Interconnection Customer is responsible for the design of its Protection System. Faults or failures on the Interconnection Customer’s Facilities may affect the DEV-ET Transmission System or other Customers tied to the system. Consequently, the Interconnection Customer’s Protection System will be designed to minimize the effects of faults and disturbances originating at the Interconnection Customer’s Facilities. The Interconnection Customer Protection System design must meet the following design principles:

- Detects all faults and abnormal conditions for which it is designed to detect (sensitivity).
- Only operates for faults and failures within its zone of protection (selective).
- Can coordinate between protection zones (no overtripping).
- Operates quickly to isolate faulted element(s).


If DEV-ET finds that the Interconnection Customer’s design is inadequate, DEV-ET will 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.

Additionally, the Interconnection Customer’s Protection System is to protect against abnormal operating conditions. These include, but are not limited to, over/under-voltage, over/under-frequency, harmonics, overloads, short circuits, open circuits, phase imbalance, switching surges, lightning surges, and other harmful electrical conditions.

Utility-grade protective relays and fault-clearing systems will be used 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.

#### 2.4.1.1 IBR Protection Systems

The response of an IBR to a fault is influenced by the inverter’s fast controls acting on changes to the IBR’s terminal conditions. Inverter controls differ between Original Equipment Manufacturers (OEMs). Therefore, each IBR has a unique response to a fault. The injection of positive-sequence current into a fault is somewhat

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consistent among OEMs, but the injection of negative-sequence current can vary greatly between OEMs. Some OEMs allow their inverters to inject negative sequence currents, and some do not<sup>3</sup>.

Protection schemes that rely on negative sequence currents may not operate correctly. To ensure the protection system is dependable and secure, IBR connections to the DEV-ET system must supply an EMT model with the IBR control setting to DEV-ET for evaluation consistent with the requirements outlined by Attachment 7.

The protection function requirements of IBRs must comply with IEEE Std 2800-2022<sup>4</sup>. Specifically, the IBR plant’s protection system must not limit the IBR plant’s ride-through capability.

#### 2.4.1.2 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. These systems provide a redundant set of all normal primary and backup functions. Further explanation can be found in IEEE Std C37.120<sup>5</sup>.

#### 2.4.1.3 Breaker Failure Protection

The protection scheme must include a breaker failure function for all interrupting devices connecting to a DEV-ET transmission bus. For generation interconnections, additional requirements are outlined in Attachment 3—DEV Generator Interconnection Protection Requirements, Section 3 Interconnection Protection Requirements.

#### 2.4.1.4 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.


For reliability, the Interconnection Customer’s Protection System must be powered by a DC battery. The battery is to be sized to power continuous loads for at least 8 hours and power all momentary tripping loads without needing a charger. The battery sizing calculation should be done following IEEE Std 485<sup>6</sup>. A DC under-voltage alarm must monitor the battery-powered DC system. This alarm must be monitored by the Facilities owner at all times using remote communications. If the DC under-voltage alarm detects a system failure and notifies the Facilities owner, it is the responsibility of the Facilities owner to take immediate action to restore power to the protective equipment. If the alarm signal is not sent directly to DEV-ET operations, then it is the responsibility of the Facilities owner to inform DEV-ET operations directly of the failure and report the status of the protection system restoration.

<sup>3</sup> Sandia Report, “Impact of Inverter-Based Resource Negative-Sequence Current Injection on Transmission System Protection,” SAND2020-0265, Jan. 2020.

<sup>4</sup> IEEE Std 2800-2022, “IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems”, Feb 2022.

<sup>5</sup> IEEE Std C37.120-2021, “IEEE Guide for Protection System Redundancy for Power System Reliability”, Nov 2021.

<sup>6</sup> IEEE Std 485-2020, “IEEE Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications”, May 2020.

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#### 2.4.1.5 Load Interconnection Requirements

Customer delivery point requests associated with Power Electronic Interface (e.g., Data Centers, Crypto mining farms) require close department-level coordination within DEV-ET Planning and Operations to ensure system reliability and operational stability. To mitigate risks associated with large load loss during disturbances, large data center customers must ensure their protection system designs account for voltage stability and ride-through capability. All customer requests with Power Electronic Interface Large Loads (PEILL) must comply with the requirements specified in Attachment 8.

#### 2.4.2 Protection System Operation and Misoperations

The Interconnection Customer is to investigate all operations and misoperations of their Protection Systems that affect the Customer’s Facility in compliance with applicable standards, including PRC-004. Within the code of conduct restrictions, DEV-ET will cooperate with the Interconnection Customer and provide its findings related to the incident. The Interconnection Customer is to provide its findings to DEV-ET.

### 2.5 Metering and Telecommunications

#### 2.5.1 Metering Equipment

DEV-ET-approved revenue Metering Equipment will 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 PJM market participants 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.
- 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 (CTs), voltage transformers (VTs), revenue meters, meter sockets, test switches, communication circuits, and associated devices. The revenue Metering Equipment will be located at the Interconnection Customer’s Facility unless otherwise agreed to by DEV-ET, PJM, and the Interconnection Customer (collectively referred to 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 the manufacturer’s installation information for the CTs and VTs when these devices are furnished by DEV-ET and installed by the Interconnection Customer.

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### 2.5.1.1 Revenue Meters

The revenue meters will be capable of recording, storing, and transmitting bi-directional megawatt-hour (MWh) and megaVAR-hour (MVARh) data. However, if required by the applicable tariffs or mutually agreed upon by the Parties, the revenue meters will record bi-directional kilowatt-hour (kWh) data and kiloVAR-hour (kVARh) data instead. Generally, this data will be recorded hourly 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. DEV-ET may request testing of meters in service, in any regulatory agency having jurisdiction over the interconnection, or any other lawfully constituted authority having jurisdiction over meter accuracy.

### 2.5.1.2 Revenue Metering Current Transformers


The revenue meters will be connected to current transformers (CT) with a minimum metering accuracy class of 0.15% (as defined in IEEE C57.13<sup>7</sup>) 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. However, 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 when the thermal current rating factor (RF) is applied. The available fault current must not exceed the mechanical and short-time thermal limits of the CTs. The revenue meters are generally 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.

### 2.5.1.3 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 also responsible for any high voltage isolation equipment that the local telecommunications company may require at the Interconnection Customer’s Facility to protect their communication 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 provided upon request are 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 both Parties agree upon such arrangements.

<sup>7</sup> IEEE Std C57.13-2016, “IEEE Standard Requirements for Instrument Transformers,” Jan 2016.

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### 2.5.2 Operational Metering Data from Revenue Meters

Operational metering data (e.g., MW and MVAR) is generally unavailable from DEV-ET revenue meters 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 a Remote Terminal Unit (RTU), to provide the following real-time bi-directional power and energy data for operational purposes:

- Instantaneous power flow.
- 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 is to be provided through the registers on the meters. The revenue meter(s) will provide bi-directional energy data flow in either KYZ pulse signals format or accumulated counters to RTU. Energy data flow accumulator counters may 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 data communication methods employed. For generation Facilities that interconnect to DEV-ET generator interconnection substations, this revenue meter data will be shared across serial data links between the two Facilities. This data is shared between Facilities at generator interconnection substations. (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.) 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 will be synchronized to Universal Time Coordination (UTC) within ½ seconds.


The revenue meters’ internal clocks and real-time DAS equipment will be synchronized with UTC with a 15-second resolution.

### 2.5.3 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. The Interconnection Customer will not permit unauthorized access to the revenue Metering Equipment regardless of meter ownership.

The meters, test switches, and any other secondary devices that could have an impact on the performance of the revenue metering are 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 ISA, PJM requirements, or regulatory commission regulations by the Metering Equipment owner.

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#### **2.5.4 Wholesale Generation Facilities Revenue Metering Equipment**

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 will be compensated for losses to the POI if the Metering Equipment is not located at the POI.

The revenue metering CTs and VTs will 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.

#### **2.5.5 Wholesale Generation Facilities Revenue Meter Requirements**

##### **2.5.5.1 Generation Connected at 69 kV or Above**

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 are 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; and other device status points (e.g., automatic reclosing on/off). It is preferred that the redundant meter have a different telecommunications method 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.

##### **2.5.5.2 Generation 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 telecommunications method than the primary meter.


##### **2.5.5.3 Generation Connected Behind-the-meter and 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 specified by the applicable retail tariff or ISA. 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.

##### **2.5.5.4 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 Interconnection 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 the Telecommunication Section.

#### **2.5.6 Transmission Owner Facilities**

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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 will 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 is to be 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 telecommunications method than the primary meter.

### **2.5.7 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 will be installed on either the primary or secondary sides of the Interconnection Customer’s step-down transformer, following 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 allows DEV-ET to choose either the primary 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 the Interconnection Customer installs revenue metering, DEV-ET must review and accept the proposed metering installation design before installation.

If the revenue metering is installed on the secondary side of the Interconnection Customer’s step-down transformer, losses in the transformer are to be compensated. The revenue metering is also to 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 will 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 1,000 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 the following configuration after DEV-ET review and acceptance of the proposed design:

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- 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. DEV-ET meter personnel must have adequate working clearances around the CT and VT secondary terminal boxes to install the secondary wires.

For the End-user Interconnection Customer’s Facility with behind-the-meter (BTM) 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 also to provide DEV-ET with the generation revenue metering data if required.

A primary revenue meter and SCADA data are required when the end user has a non-conforming load. A non-conforming load is a load of more than 50 MW that exhibits one or 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 IEEE Std 1453.
- Loads that may create harmonic current distortions exceeding the limits set out in IEEE Std 519.

**2.5.8 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, 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 one Party requires a backup telemetry system or data for its use, the requesting Party is 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) will 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, are to be provided to PJM to fulfill its roles as Reliability Coordinator (RC), BA, and Transmission Operator (TOP).

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Metering, data, and communications requirements between a Customer’s 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 Customer’s Facility and the DEV-ET interconnection station are specified in Attachment 5—Electric Transmission Generator Interconnection Data Communication and Data Exchange Requirements.

## 2.6 Grounding and Safety Issues

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

- Personnel safety: Ensure that Facility personnel, their contractors, and the public are not exposed to harmful step-and-touch potentials.
- 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 Facility must have a grounding system or grid that solidly grounds all metallic structures and equipment following 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 under the latest revision of IEEE 80.

Utility-scale solar power plants cover large areas and present a special case for grounding. The interconnection substation for a solar power plant would follow IEEE 80, but grounding practices for the solar field may differ from IEEE 80. Therefore, new solar power plant interconnections are recommended to include IEEE Std 2778-2020, *IEEE Guide for Solar Power Plant Grounding for Personal Protection*, in their design.

When various switching devices are opened on an energized circuit, their ground reference may be lost if all sources are not effectively grounded. This situation may cause overvoltages 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 must be effectively grounded from all sources.

This is defined as follows:


$$X0/X1 \leq 3$$

$$R0/X1 \leq 1$$

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.

Where applicable, shield wires should be considered to protect conductors and equipment from lightning strikes. A recommendation for maximum resistance values for all new stand-alone (not connected to a ground

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grid) structures carrying shield wires is 25 Ohms for structures supporting Facilities at or below 230 kV and 20 Ohms for structures supporting Facilities from above 230 kV to 500 kV.

Tapped transformers on transmission lines are prohibited from passing grounds to the distribution system or acting as ground sources for the transmission line zone. Existing installations that are ground sources to the Transmission System are accepted as-is. However, the new tapped transformer must comply with updated grounding requirements upon transformer replacement. Specifically, tapped transformers must use either an ungrounded high-side wye configuration or a high-side delta configuration to prevent ground paths to the Transmission System.

Safety is of utmost importance. Any work conducted within a Facility must follow all applicable laws, rules, and regulations and comply with the Occupational Safety and Health Administration (OSHA), NESC, and Good Utility Practice. Automatic and manual disconnect devices, with visible disconnect, 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 on switching and Lock Out/Tag Out procedures that are adhered to for the safety of all personnel. DEV-ET follows its standard operating practices and grounding procedures for personnel safety.

## 2.7 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 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 the ground.
- Mechanical support: Mechanically support energized parts as intended.

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


**Table 2. BIL: Electrical Equipment and High-voltage Substation Buses I**

Equipment and Bus Nominal Voltage Rating (Phase-to-phase) kV, rms	BIL (Phase-to-ground) kV, crest
115	550
138	650
230	900
500	1,550

Equipment BIL shielding and surge protection will 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 the following:

- TE VEP 1115–Porcelain and Glass Insulators.

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- 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 Delivery Point Request, 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.


## **2.8 Voltage, Reactive Power, and Power Factor Control**

### **2.8.1 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 stably operating their units 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 must follow the current NERC and SERC standards and guides for generator operation, protection, and control.

- All synchronous generators will be operated with their excitation system in automatic voltage control mode unless PJM approves them. PJM and DEV-ET are notified whenever a generator control system is removed from service or its control logic is modified. These control systems may include, but are not limited to, voltage regulators, power system stabilizers, governors, 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. The generator step-up and auxiliary transformer are to have their tap settings coordinated with the voltage requirements of the electric system.
- All new IBRs—such as wind, solar, and batteries—connected to the DEV-ET system must provide leading and lagging reactive power. This includes but is not limited to day-to-night and night-to-day voltage support. The duration of the voltage support will not be limited by any facility component. Before

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commissioning, any logic associated with voltage support capability must be enabled and turned ON to allow an operator to control the Automatic Voltage Regulator (AVR) setpoint via the SCADA system. During commissioning, testing will be done to confirm that the IBR can supply continuous voltage support during daytime hours and nighttime hours and that it can transition from day to night or night to day.

- For battery storage systems, charging, discharging, and idle modes will be tested to show that the system can supply voltage support. Requirements for the DEV-ET SCADA voltage setpoint control function are found in Attachment 5—Generator Interconnection Data Communication and Data Exchange Requirements.
- Temporary excursions in voltage, frequency, and real and reactive power output that a generator can sustain are 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 new generation interconnection requests and generators seeking to increase their output must adhere to the power factor requirements documented in Section 4 of the PJM Manual 14G, *Generation Interconnection Requests*. PJM will perform a System Impact Study (SIS) to determine asynchronous generators’ reactive power compensation requirements.


All interconnected generation must meet the following criteria:

- All new synchronous generators connecting to the Transmission System will be designed to deliver continuous rated power with a power factor in the range of 0.95 leading to 0.90 lagging at the high side of the Facility substation transformer.
- All new wind-powered and non-synchronous generators (IBRs) connecting to the Transmission System will be designed to deliver continuous rated power with the maximum feasible amount of reactive power support at any active power output at the high side of the Facility substation transformer.
- All new intermittent resources (wind and solar) connecting to the Transmission System will be 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 will provide input and support these studies as needed. The SIS for asynchronous, intermittent generation will consider the generator under study and the variability of the entire intermittent generation fleet when determining if the voltage fluctuation criteria are met.
- Voltages at the POI 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.
- New variable generation resources that cannot meet the 1% voltage deviation criteria provide dynamic reactive compensation as specified in the PJM SIS, 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 SIS. These specific requirements for a generator will be part of the ISA (PJM Manual 14A, Section 5: Summary of Agreements).

**2.8.2 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. All new

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Transmission Facilities must be designed to support system voltage when the Transmission System is heavily loaded and to prevent excessively high voltages when the Transmission System is lightly loaded.

### **2.8.3 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 close to the unity power factor to minimize the reactive power burden on the Transmission System.

## **2.9 Power Quality**

New interconnections shall not adversely impact the power quality of the power system. At no time shall instantaneous voltage fluctuations caused by the Customer exceed 3% to avoid negatively impacting service quality to adjacent customers. As such, the Customers will be responsible for adding the equipment necessary to eliminate or minimize the adverse impact identified by DEV-ET.

### **2.9.1 Flicker Requirements**

As discussed in IEEE Std 1453, Flicker will be measured at the Point of Common Coupling (PCC) using an instrument compliant with International Electrotechnical Commission (IEC) 6100-4-15.

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

IBR interconnections shall be subject to requirements and emission limits in Section 8.1.3 of IEEE Std 2800-2022.

### **2.9.2 Harmonic and Inter-harmonic Requirements**


Harmonic levels are measured 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 Std 519.

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

New interconnections that are solely or include IBR must also comply with IEEE Std 2800-2022 for harmonic and inter-harmonic requirements. The current distortion levels must remain within the limits in Section 8.2.1 of IEEE Std 2800-2022.

## **2.10 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.

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All current-carrying equipment and devices will be designed to carry the maximum loads 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 and Instrument transformers are to be designed and tested according to IEEE C57 standards. Rigid bus structures are to be designed to meet the latest revision of IEEE 605. Current-carrying conductors and tubing will 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 designed for voltages greater than 230 kV are considered extra-high voltage (EHV) and designed accordingly.

Equipment BIL, shielding, and surge protective device application must meet requirements 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.

**Table 3. BIL: Electrical Equipment and High-voltage Substation Buses II**

Equipment and Bus Nominal Voltage Rating (Phase-to-phase) kV, rms	BIL (Phase-to-ground) kV, crest
115	550
138	650
230	900
500	1,550


## **2.11 Synchronizing of Facilities**

Synchronizing equipment consisting of potential devices and associated protective relays and controls is required in Facilities where energy can be sourced from both sides of an interconnection circuit breaker. The Interconnection Customer is not to synchronize with the Transmission System before obtaining approval from DEV-ET. Before the synchronization of Facilities, the Interconnection Customer must validate conformance between equipment device labels and naming conventions between DEV-ET and Interconnection Customer systems.

The following subsections explain the various synchronizing options.

### **2.11.1 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 with the Transmission System. Instead, the generation Facilities should have their synchronizing Facilities. If a generation Interconnection Customer’s Facility becomes disconnected from DEV-ET’s system, it must 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.

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**2.11.2 Interconnected and Separate Systems for Generators**

The Interconnection Customer may run its generator in parallel (interconnected) with DEV-ET or as a separate system capable of non-parallel load transfer between the two independent systems.

**2.11.2.1 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 power transfer 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 in Facilities where energy can be sourced on both sides of an interconnection circuit breaker. This equipment serves the following purposes:

- Verifies that 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.


**2.11.2.2 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 non-parallel mode. This can be accomplished by either an electrically or mechanically interlocked switching arrangement that precludes 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 will not operate the system until DEV-ET has verified that the transfer scheme meets the nonparallel requirements. This verification is accomplished by reviewing and approving drawings and equipment specifications by DEV-ET and, if DEV-ET 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.

**2.11.3 Maintenance Coordination**

**2.11.3.1 Testing**

DEV-ET requires interconnecting entities with protection systems that coordinate with DEV-ET network protection systems to have a documented maintenance program for those systems following 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 its documented program and following any apparent malfunction of the protection equipment, is to perform and document calibration and functional trip tests of its protection equipment as outlined within its maintenance program. The interconnecting entity is to maintain evidence of such activities and make them available to DEV-ET upon request.

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### 2.11.3.2 Coordination

DEV-ET may remove its lines and associated equipment from service to test relays and maintain lines or substations following 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 bulk electric system (BES).

### 2.11.3.3 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 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.

## 2.11.4 Operational Issue (Abnormal Frequency and Voltage)


PJM is the TOP for the DEV-ET System. The Interconnection is operated in a manner consistent with PJM requirements and procedures. Specific transmission conditions and procedures for operating Transmission Facilities (defined by PJM) within PJM are found in PJM Manual 03–Transmission Operations on the PJM website ([www.pjm.com](http://www.pjm.com)).

## 2.11.5 Load Shed Program as Required by PJM

The Transmission System is designed to automatically activate a load-shed program as PJM requires in 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 the 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, following 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, including both under-frequency and over-frequency deviations, is studied and coordinated with PJM following Good Utility Practice. Additional information is found in PJM Manual 14D–Generator Operational Requirements. Inspection requirements for new or Qualified Changes to existing Interconnections.

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

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

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At its own expense, each party has 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. The Customer is to provide DEV-ET with a corrective action plan resolving the identified concern(s).

If the 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.

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


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

- Contact information for maintenance personnel. Customers must provide detailed contact information of involved personnel, identifying roles and responsibilities, and must be updated as frequently as changes in personnel are identified.
- 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.

Depending on the interconnect category, various communication channels may be used in emergencies or abnormal operating conditions. Both parties should agree upon emergency telephone numbers before 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 the operation of the Interconnection Customer’s Facility, the Interconnection Facilities, the DEV-ET Interconnection Facilities, or the Transmission System.

**2.11.7 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 the DEV-ET system dispatcher. Generation and transmission Interconnection Customers must adhere to the

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requirements outlined by PJM Manual 03 (Section 4) and provide notice as far in advance as possible. Generation and transmission Interconnection Customers are to provide standard voice lines, dedicated voice lines, and facsimile communications at their Facility control room through the public telephone system. Generation and transmission Interconnection Customers must also provide and maintain backup communication links specified by 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.

## 2.12 Transmission Line Connections: Generation

Transmission Facilities may provide service to generation developers when using 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 500 kV network, the preferred minimum generation capability at a single point of connection is 500 MW. The interconnection of generating plants on the 500 kV network below this level is permitted for cases with no other lower transmission voltage option.

Proposed generating Facilities connecting to the Transmission System must not form multi-terminal lines. Multi-terminal lines are created when more than two sources are connected directly to a transmission line. Multi-terminal transmission lines created by proposed generating Facilities are prohibited regardless of the generating Facility Capacity.

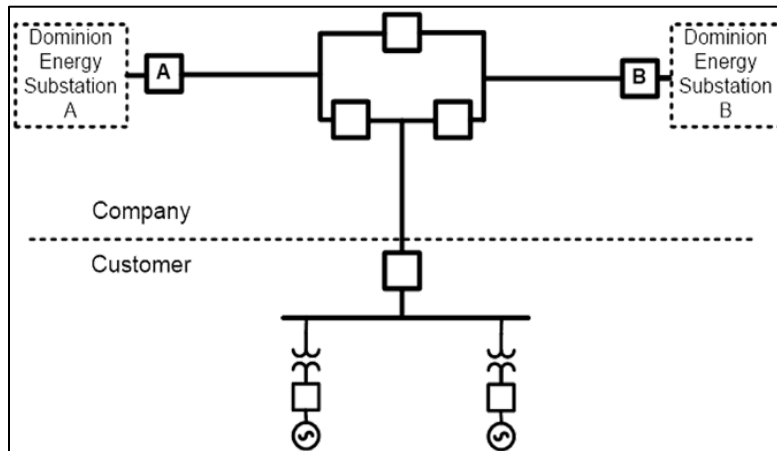
Customers proposing generating Facilities must reconfigure the Transmission System to accommodate their Facilities. If two generating sources are connecting to the same POI, the interconnection substation should be configured such that each source is connected through a dedicated breaker.

The proposed generating Facilities must not negatively impact the Transmission System’s reliability. The descriptions and figures in this section are typical from an interconnection standpoint. They are subject to further modification to comply with Attachment 3—DEV Generator Interconnection Protection Requirements, Section 3—Interconnection Protection Requirements.

### 2.12.1 Single Circuit Interconnection to a Transmission Line

Typically, the arrangement shown in Figure 1 can be used to interconnect a new generating Facility of any size located within one mile of the Transmission System. This is DEV-ET’s typical arrangement for generation interconnections. The arrangement can also be used to interconnect Facilities of 500 MW or less and will be located more than one mile from the Transmission System. With this arrangement, generation loss does not interrupt flow on the Transmission System, and transmission line loss does not result in generation loss. However, final System Protection requirements and interconnection substation requirements will 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 the property for the construction of the DEV-ET-owned interconnection station.

Violations of DEV-ET Planning Criteria found in Section 3 of Attachment 1 may require additional circuit breakers beyond the three shown in Figure 1.



**Figure 1. Generator Connecting to Adjacent Transmission Line**

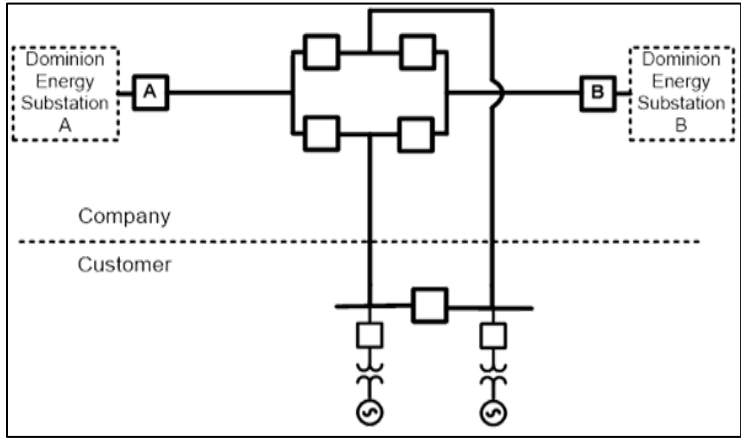
### 2.12.2 Transmission Interconnections Located Remote from a Transmission Line

If the proposed generating Facility is greater than 500 MW and located more than one mile from an existing transmission line, the proposed arrangement in Figure 2 or Figure 3 could be used. With these arrangements, the loss of generation does not interrupt flow on the Transmission System, and the loss of a transmission line does not result in generation loss. Arrangement A, shown in Figure 2, places the interconnection substation next to the transmission line. Arrangement B, shown in Figure 3, places the interconnection substation next to the generation site.

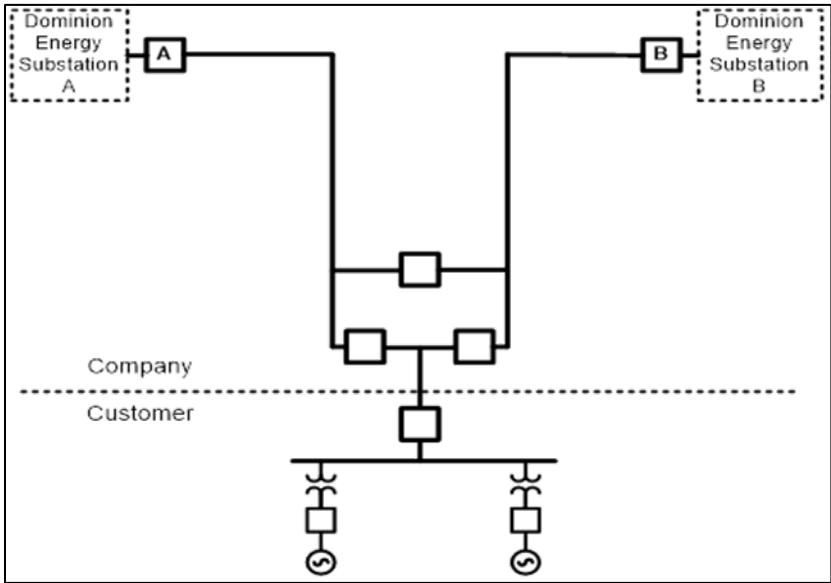
Violations of DEV-ET Planning criteria found in Section 3 of Attachment 1 may require additional circuit breakers beyond those shown in Figure 2.

The Customer must reserve the property to construct the DEV-ET-owned Interconnection station.

The final System Protection and interconnection substation requirements will be based on the reliability impact assessment conducted through the PJM Interconnection Queue process defined in PJM Manual 14C–Generation and Transmission Interconnection Facility Construction.



**Figure 2. Arrangement A for Large Generation Facility Over 1 Mile from Transmission Line**




**Figure 3. Arrangement B for Large Generation Facility Over 1 Mile from Transmission Line**

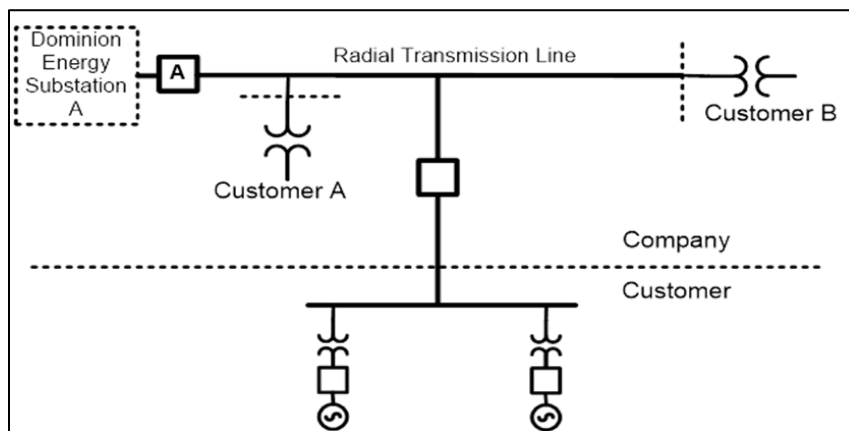
**2.12.3 Interconnection to Radial Transmission Line**

A proposed generating Facility may be connected to a radial transmission line. A radial transmission line is a single line with one transmission source. It does NOT tie to any other transmission network source (line or substation) or existing generation source.

As shown in Figure 4, a proposed generating Facility may be connected to a radial transmission line. This is subject to protection requirements documented in Attachment 3—DEV Generator Interconnection Protection Requirements, Section 3—Interconnection Protection Requirements.

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Proposed generating Facilities must be reviewed to ensure they will not form multi-terminal lines. Multi-terminal lines are created when more than one generating Facility is connected directly to a transmission line. Multi-terminal transmission lines created by proposed generating Facilities are prohibited.



**Figure 4. Connection to a Radial Transmission Line**

#### **2.12.4 Isolation Device**

A visible-break isolation device will be installed between DEV-ET and the generator. DEV-ET will own the device. In the case of a Gas-insulated Substation (GIS), the generator Interconnection Customer will consult with DEV-ET to determine an alternative means to provide DEV-ET workers with a method to confirm that the generation substation is not connected to the DEV-ET system.

#### **2.12.5 Substation Interconnection Requirements**

All generation interconnection substation designs include all switches and devices required to permit maintenance of all breakers and transmission lines without losing the ability to use the generation Capacity when required. Small units can be bused together behind breakers unless reliability studies indicate issues. For more information, refer to Attachment 6—Generation Interconnection Substation Technical Requirements.

#### **2.12.6 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 fewer, ring bus are acceptable. Violations of DEV-ET planning criteria found in Section 3 of Attachment 1 may require additional circuit breakers beyond those described above.

#### **2.12.7 Generation Interconnection Breakers**

Figure 5 shows two possible circuit breaker arrangements: low-side circuit breakers on the generators with a single high-side circuit breaker on the transmission line and high-side circuit breakers on the generators. Both arrangements provide similar protection.

The final System Protection and interconnection substation requirements will be based on the reliability impact conducted through the PJM Interconnection Queue process defined in PJM Manual 14C—Generation and Transmission Interconnection Facility Construction.

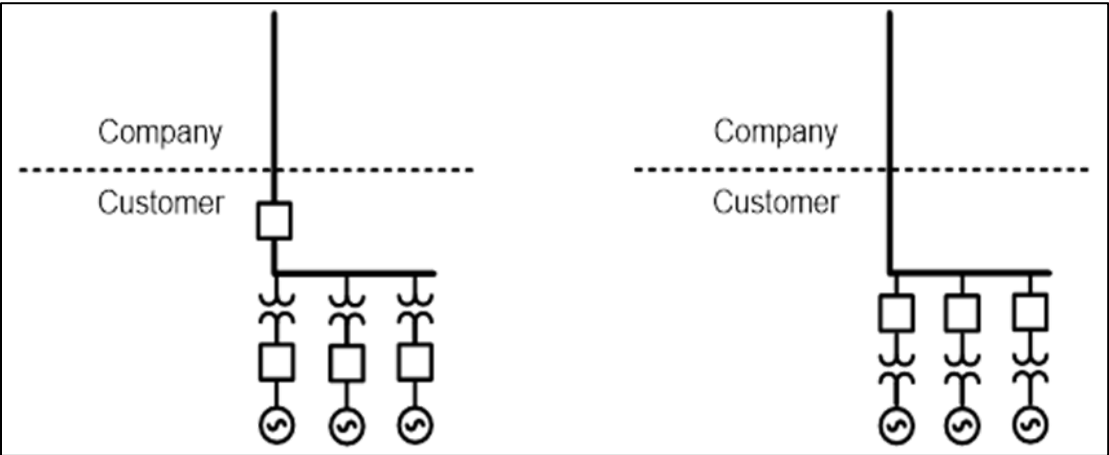


Figure 5. Potential Circuit Breaker Arrangements for Generation Substations

**2.12.8 Interconnection Requirements for Distribution Connected Generation**

Distribution-connected generation is defined as a generator that requests 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. Figure 6 shows an example of generation connecting to the distribution system through a distribution transformer.

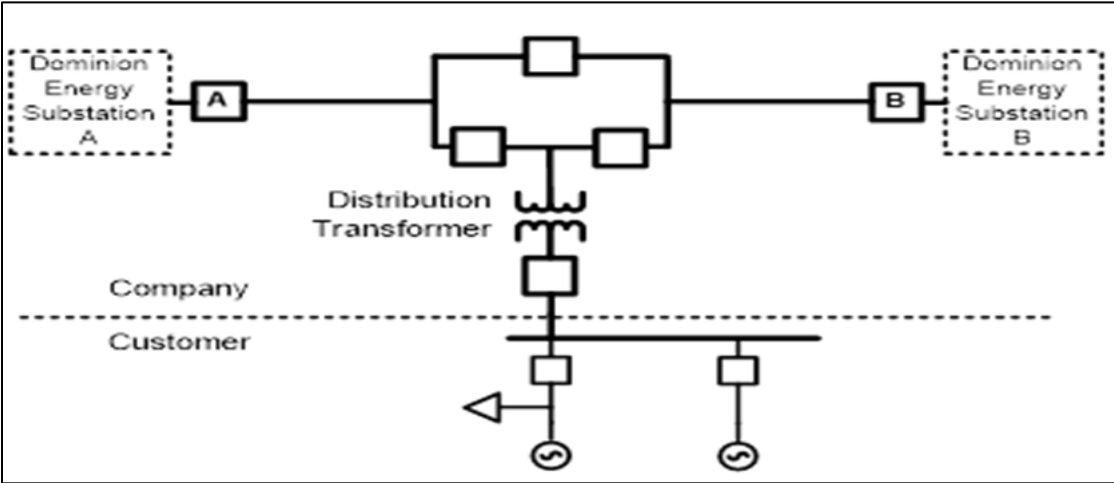

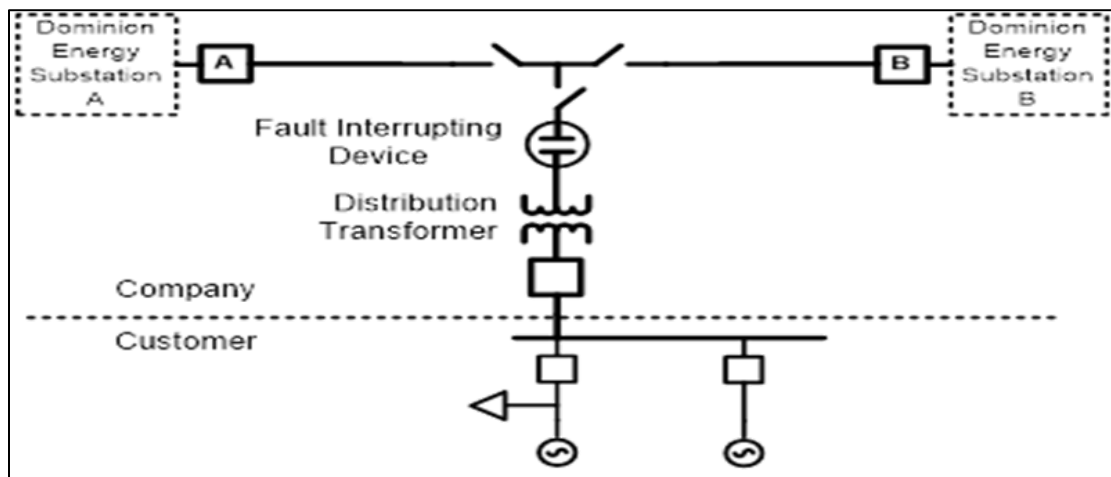


Figure 6. Distribution Connected Generation Greater than 100 MVA

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



**Figure 7. Distribution Connected Generation Less than 100 MVA**

### 2.13 End-user Facilities (Load Interconnection)


Transmission Facilities may be used to provide service to commercial, industrial, municipal, cooperative, and cogeneration Customers when using 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 is permitted after a thorough planning analysis conducted by DEV-ET 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 the 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.

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The feasibility of serving Customers directly from transmission and determining the final recommended transmission Interconnection Facilities requires a comprehensive study by DEV-ET and coordination. Factors to be considered before agreeing on a Customer connection are as follows:

- Economics of distribution versus transmission alternates.
- 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 that the actual load varies materially from the 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.
- Customer Generation strategy and corresponding protection schemes.
- Backup Generation (designed to operate in islanded mode).
- Parallel Generation (designed to operate in parallel with the DEV-ET system).

Generally, a tap line of more than one mile requires a terminal station. A three-breaker or four-breaker ring bus may be required if the tap line is long enough to require a terminal substation. With these arrangements, the loss of a line to the Customer does not interrupt the flow of the Transmission System, and the loss of a transmission line does not result in a loss of service to the Customer. The total projected load and MW-Mile exposure are also factors to consider. However, the final number of breakers and breaker arrangements is based on the specific interconnection request and reliability impact on the Transmission System.

Radial transmission lines serving generation Facilities must not be tapped to connect a load, as this can compromise reliability for both the generation Facility and existing Customers by increasing fault exposure and operational risks. Interconnection Customers seeking to connect a load to these radial lines must reconfigure the system to ensure their facility does not impact the reliability or continuity of service for the generation facility or existing DEV-ET Customers.

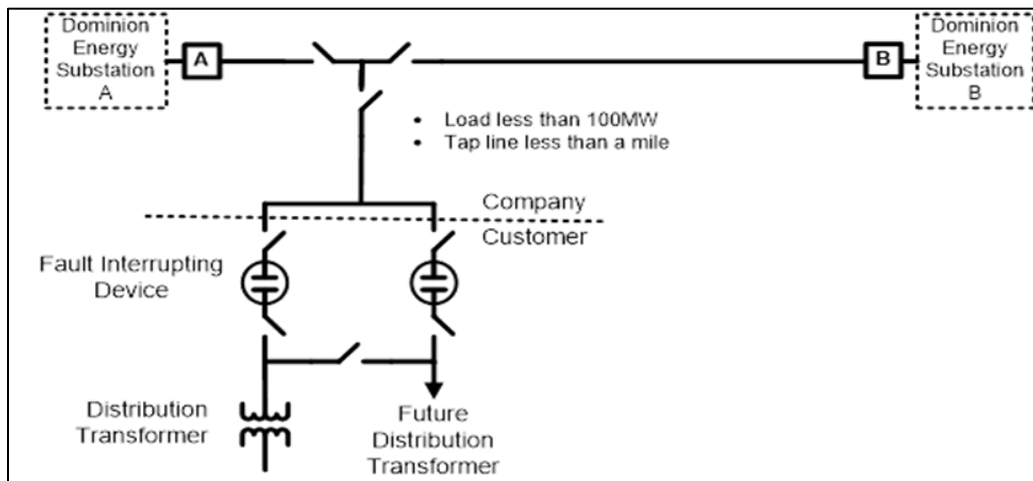
Interconnection Customers with large loads behind a POI must provide detailed information about their Facility’s behavior during Transmission System events. This includes specifying whether the Facility will disconnect during such events and, if so, providing comprehensive documentation on how the Facility’s controllers will execute the disconnection. All Interconnection Customers with PEILL must comply with the requirements in Attachment 8.

**2.13.1 Tapping Line for Loads Below 100 MW**

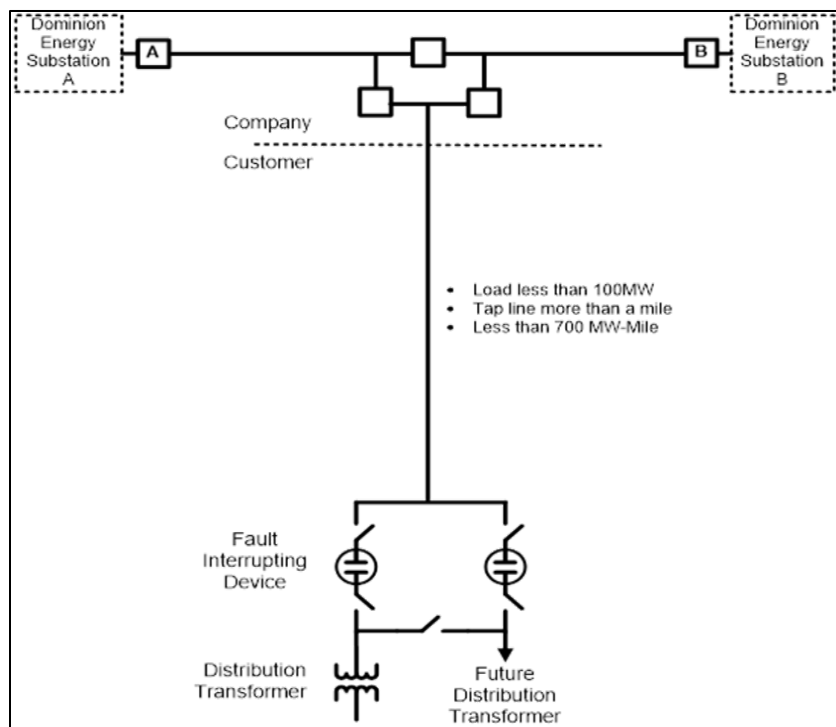
As shown in Figure 8, a transmission line tap can be used to interconnect a proposed Customer Facility when the distance from the tap point to the load substation is one mile or less. However, all proposals are subject to the planning criteria outlined in Attachment 1. For this arrangement, the company installs necessary system protection equipment and associated components at the Customer’s Facility.

As shown in Figure 9, a transmission line tap can be used to interconnect a proposed Customer Facility when the distance from the tap point to the load is greater than one mile. A three-breaker or four-breaker ring bus may be required. For this arrangement, the company installs all necessary equipment at the interconnection substation at or near the transmission line.

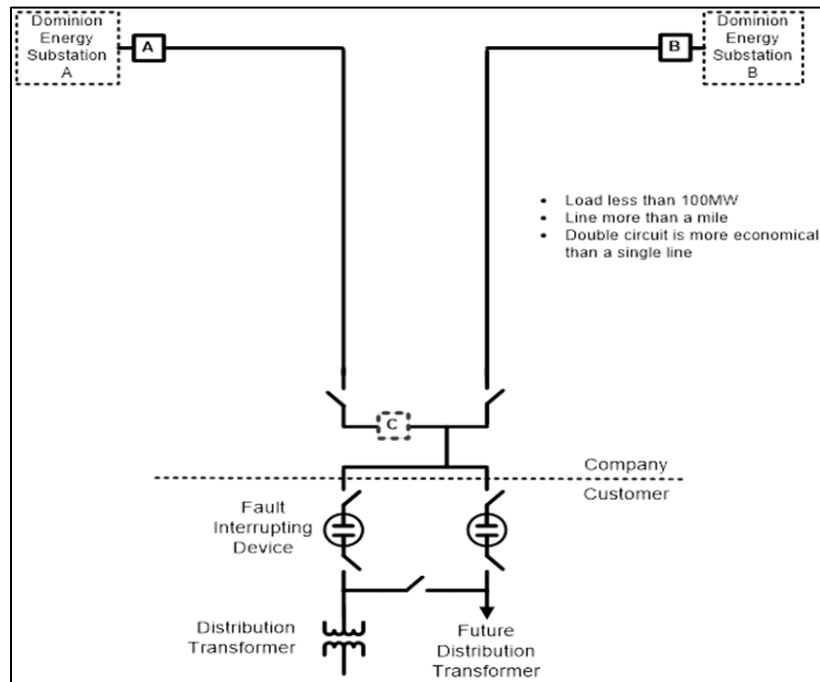
The final System Protection and interconnection substation requirements communicated to the Customer will be based on the site-specific detailed reliability impact determined by DEV-ET.



**Figure 8. Tapped Line for Less than 100 MW, Less than 1 Mile**



**Figure 9. Tapped Line for Less than 100 MW, More than 1 Mile, Less than 700 MW Mile**



**Figure 10. Tapped Line for Less than 100 MW, More than 1 Mile, Two Feeds**

A transmission line tap, as shown in Figure 10, can be used to interconnect a proposed Customer Facility of less than 100 MW, and when building a double circuit rather than a single line is more economical. The Customer may reserve the property for the DEV-ET-owned interconnection station if one is required.

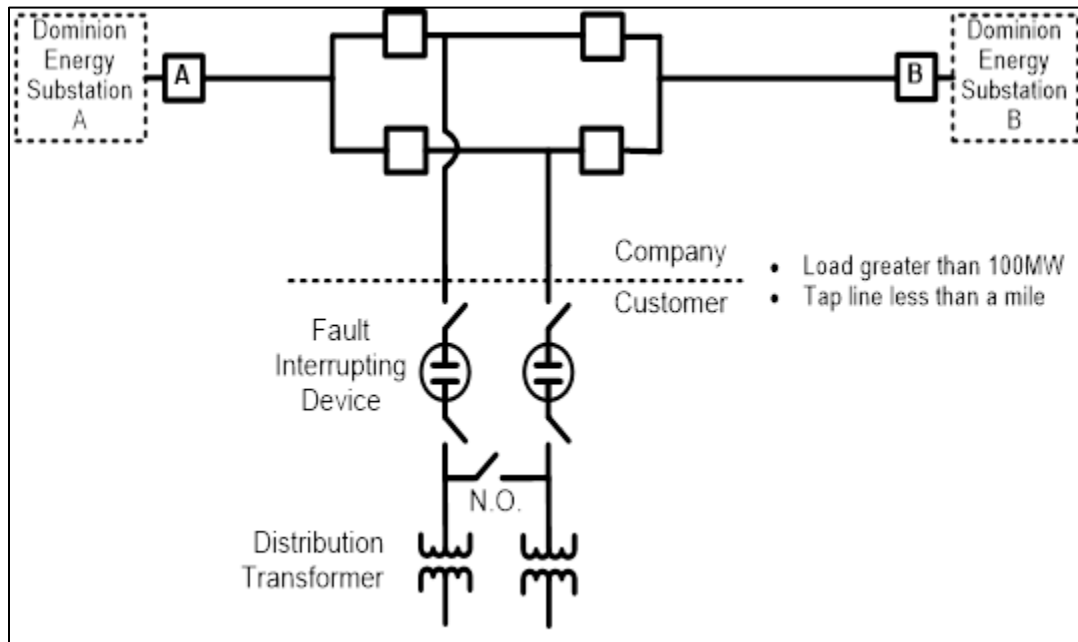
The addition of breaker “C” (as shown in Figure 10) may be required to limit the number of direct-connect loads (tapped Facilities) to four or as otherwise required based on detailed System Protection and interconnection substation assessments.

On distribution transformers directly connected to DEV-ET equipment, the Interconnection Customer is responsible for ensuring that the interrupting device complies with one of the following configurations:

- A fuse capable of sufficiently clearing high-side faults.
- A circuit switcher or breaker with an interrupter failure scheme. This will require communication equipment specified at the tap point and terminal station(s). In the event of a failed interrupting device, the communication channel(s) will be used to prevent repeated reclose attempts on the transmission line and clear a distribution fault that may go undetected by transmission line protection.
- A circuit switcher or breaker with a series Motor-operated Air Breaker (MOAB), where the MOAB is operated simultaneously with the interrupting device by the transformer protection. The MOAB in this configuration must be capable of isolating the transformer as part of the protection system.

### 2.13.2 Tapping Lines for Loads 100 MW and Greater

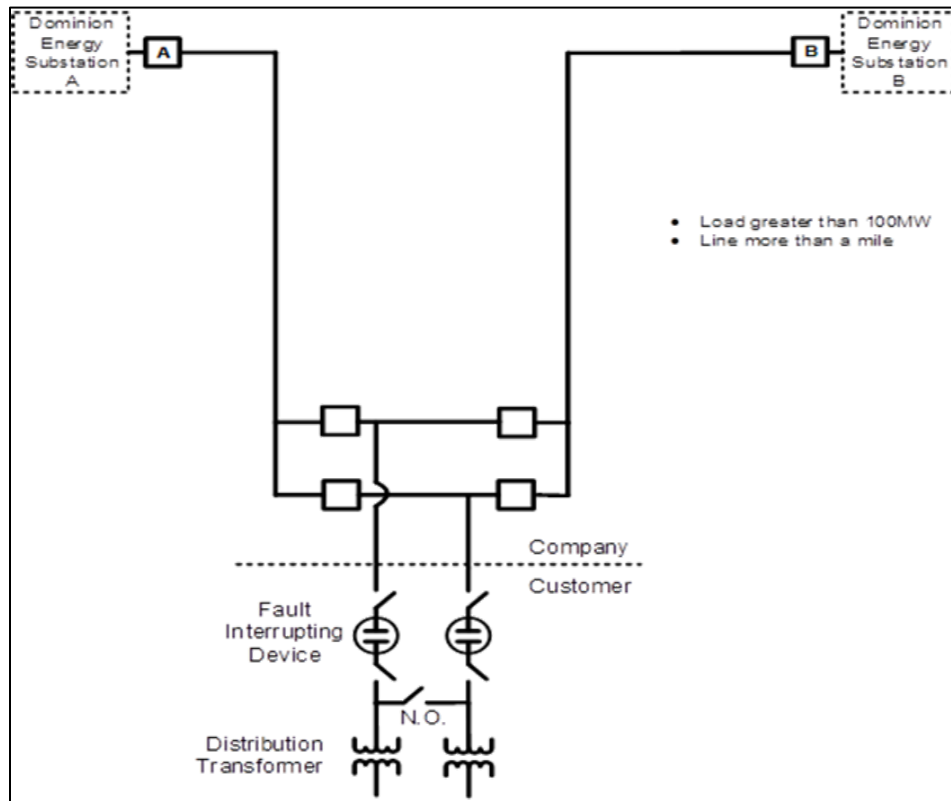
Adding a Customer load of more than 100 MW should be connected to the Company’s Transmission System, as shown in Figure 11 and Figure 12. When available, 230 kV transmission lines are the preferred voltage level to connect loads greater than 100 MW.



**Figure 11. Tapped Line for Greater than 100 MW, Less than 1 Mile**

As shown in Figure 11, a four-breaker ring bus arrangement can be used to interconnect a Customer's Facility of 100 MW or greater having two Customer transformers or to address a specific violation of the NERC standard outlined in Section 3 of Attachment 1. A three-breaker ring bus may be acceptable for cases with only one Customer transformer. With either arrangement, the loss of a line to the Customer does not interrupt the flow of the Transmission System, and the loss of a transmission line does not result in a loss of service to the Customer.

The final System Protection and interconnection substation requirements communicated to the Customer will be based on the site-specific detailed reliability impact determined by DEV-ET. The Customer could reserve the property for the construction of the DEV-ET-owned interconnection station if the Customer parcel is adjacent to or in very close proximity to the transmission right of way.



**Figure 12. Tapped Line for Greater than 100 MW, More than 1 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 adjacent to the Customer station, as shown in Figure 12. This arrangement can have advantages since acquiring land and permitting a new station at the tap point would not be required. The Customer should reserve property for the construction of the DEV-ET-owned interconnection station.

A four-breaker ring bus arrangement, as shown in Figure 12, can be used to interconnect a proposed Customer Facility of 100 MW or greater having two Customer-owned transformers or to address a specific violation of the NERC standard outlined in Section 3 of Attachment 1. A three-breaker ring bus may be acceptable for cases with only one Customer-owned transformer. With either arrangement, the loss of a line to the Customer does not interrupt the flow of the Transmission System, and the loss of a transmission line does not result in a loss of service to the Customer.

On distribution transformers directly connected to DEV-ET equipment, the Interconnection Customer is responsible for ensuring that the interrupting device complies with one of the following configurations:

- A fuse capable of sufficiently clearing high-side faults.
- A circuit switcher or breaker with an interrupter failure scheme. This will require communication equipment specified at the tap point and terminal station(s). In the event of a failed interrupting device, the communication channel(s) will be used to prevent repeated reclose attempts on the transmission line and clear a distribution fault that may go undetected by transmission line protection.

- A circuit switcher or breaker with a series MOAB, where the MOAB is operated simultaneously with the interrupting device by the transformer protection. The MOAB in this configuration must be capable of isolating the transformer as part of the protection system.

## 2.14 Prohibited Arrangements and Allowable Alternatives

DEV-ET does not allow bypass switches around primary interrupting devices on the Customer’s distribution transformer at the POI, as shown in Figure 13. DEV-ET’s current System Protection principles require that each system Element (e.g., 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 the 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. An air-break bypass switch would expose the Customer’s personnel and equipment in an unprotected zone. This risks the BES’s integrity and impacts all other Customers served by the same transmission line.

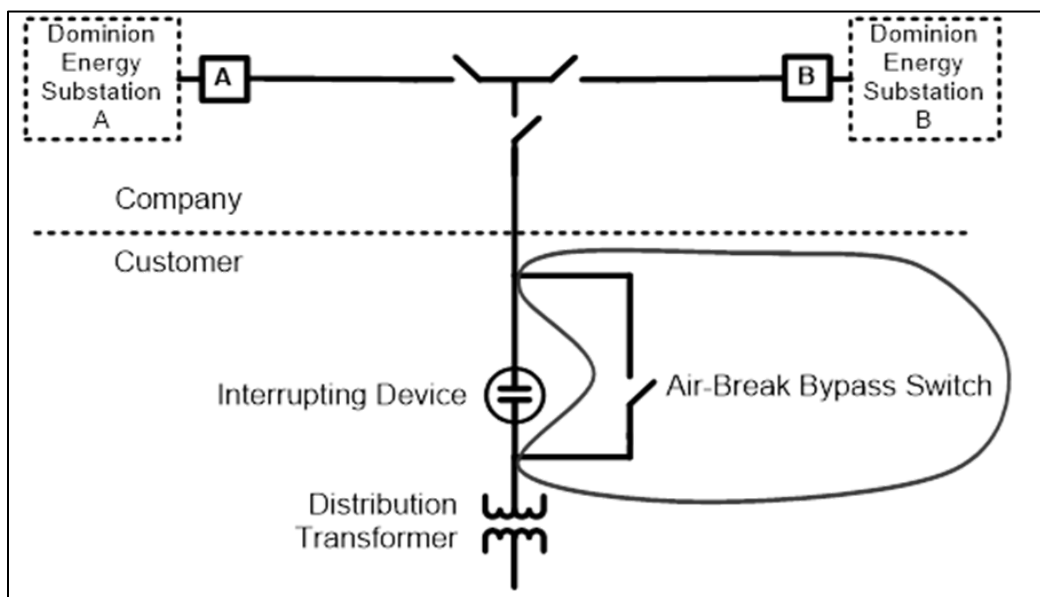
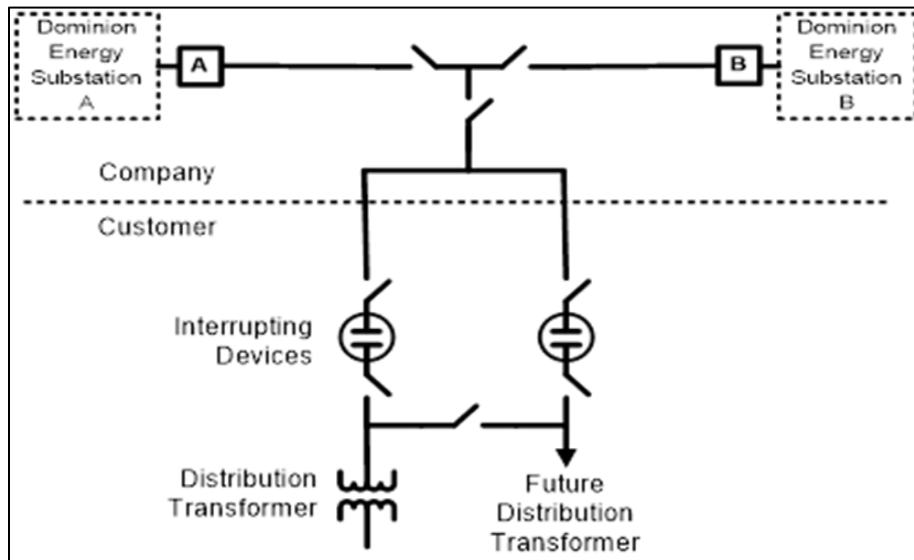


Figure 13. Prohibited Bypass Switch

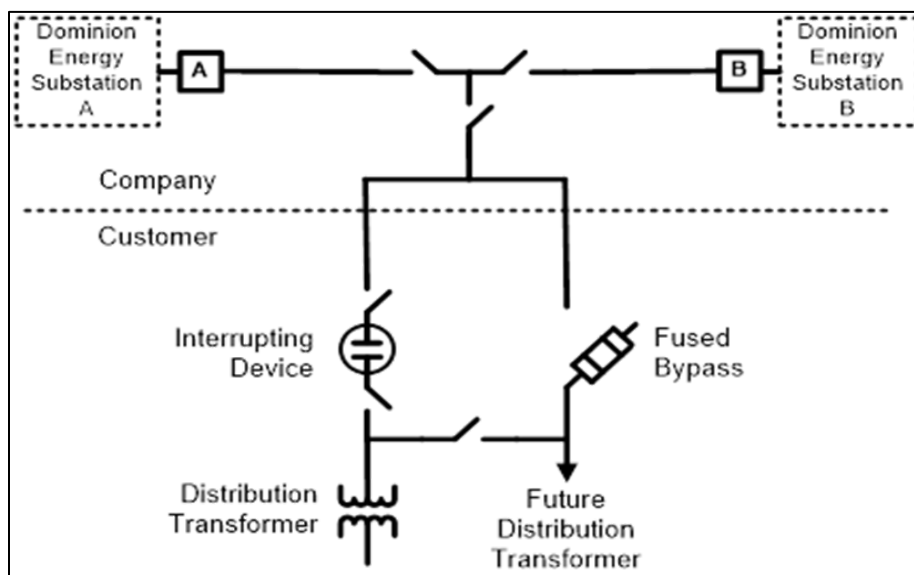
### 2.14.1 Allowable Sample Alternatives

As shown in Figure 14, a parallel circuit switcher arrangement provides a fully redundant capability. Another approach is the fused bypass, as depicted in Figure 15.

The exact design, system protection configuration, and operating arrangement may be customized as necessary and are subject to review and approval by both DEV-ET and the Customer.



**Figure 14. Allowable Alternative with Interrupting Devices**



**Figure 15. Allowable Alternative with Fused Bypass**

### 2.15 Tapping Company's Bus

The requirements for direct interconnection to the Company's transmission bus are determined case by case. The following are preferred minimum load levels within the 10-year planning horizon for the direct interconnection of loads to the existing substation buses:

- 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, Figure 16 indicates the typical Facilities arrangement for normal service.

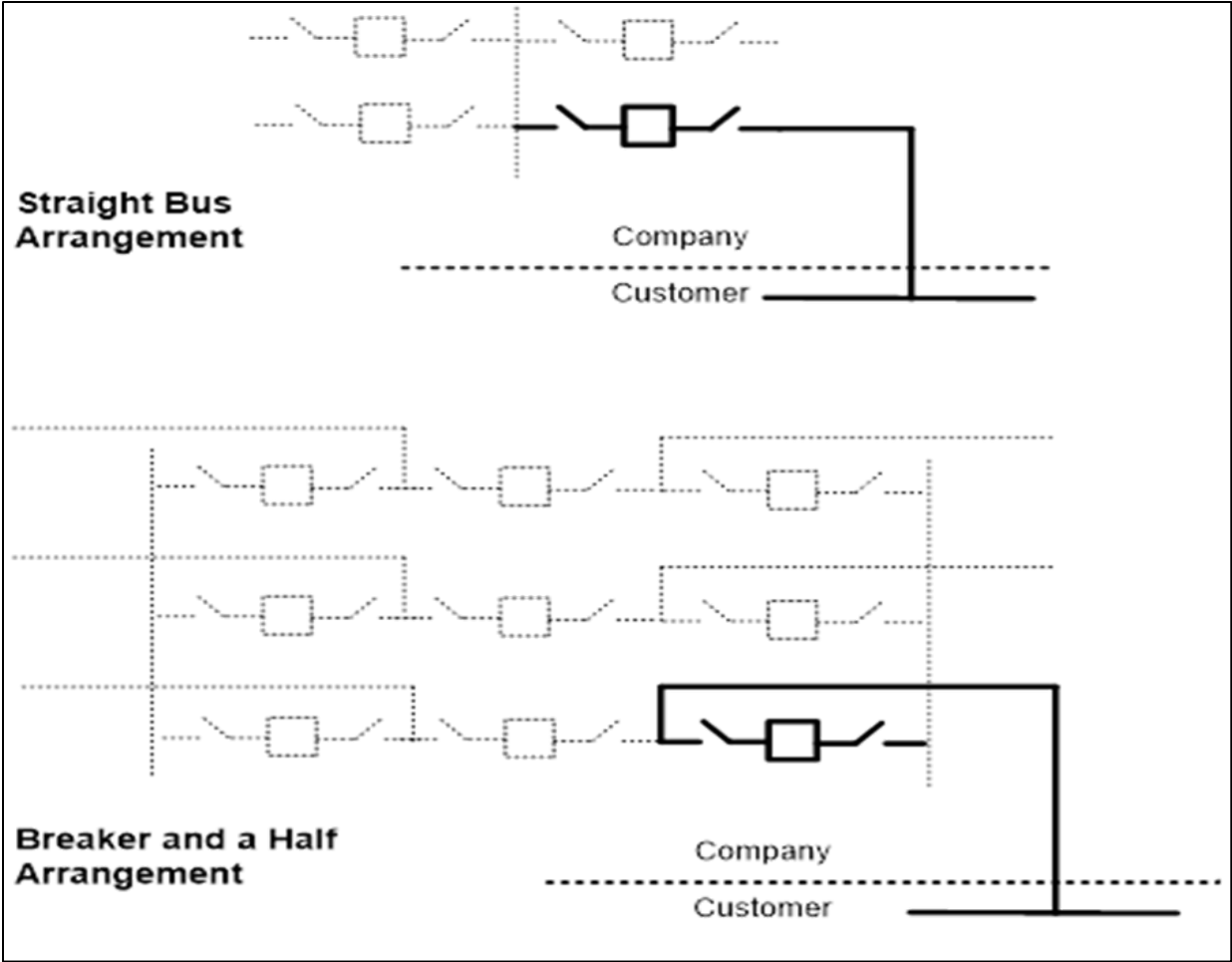


Figure 16. Connecting to the Existing Substation with a Load of Less than 100 MW


### 3.0 OPTION TO BUILD

#### 3.1 Summary

Some Customers may choose to build all the substation and Transmission Elements required to create an interconnection to the DEV-ET system.

#### 3.2 Requirements

Customers choosing to build all the substation and Transmission Elements themselves instead of having DEV-ET construct the interconnection will be required to build to DEV-ET standards using DEV-ET-approved

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equipment and material suppliers. A nondisclosure agreement (NDA) must be signed by the Customer and the Customer’s contractors before DEV-ET standards documents can be released.

During construction, DEV-ET will perform inspections, at the Customer’s expense, to ensure that the construction meets DEV-ET standards. The Customer will bear any costs incurred because of the Customer’s contractor or the Customer not following DEV-ET standards, not using approved equipment, or not using approved material suppliers.

## **4.0 IBR ENTER SERVICE COMMISSIONING (IBRESC)**

### **4.1 IBR Enter Service Commissioning Introduction**

The Inverter-Based Resource Enter Service Commissioning (IBRESC) is a structured commissioning process that consists of two separate and distinct Quality Assurance Programs (QAPs), the Configuration Management & Control Program (CMCP), and the Witness Testing Program (WTP). These programs apply to IBRs, including solar, wind, and battery storage Facilities interconnecting to the DEV-ET grid network at Transmission-level voltages ranging from 69 kV to 500 kV.

During the interconnection process of IBRs, both CMCP and WTP are mandatory components of the Enter Service Commissioning (ESC) phase of the project. An IBR site becomes eligible for ESC inspections once all site construction is complete and all digital equipment (e.g., inverters and Power Plant Controllers [PPCs]) has been fully programmed. Upon successful completion of both the CMCP and WTP, the IBR site is issued permission to operate.

### **4.2 CMCP Goal**

The goal of the CMCP is to establish the Configuration Management & Control Equilibrium (CMCE) between the DEV-ET IBR Design Requirements (what is required to be there), Configuration Information (what we say is there), and Physical Configuration (what is actually there).

**CMCE** is the ideal state that the DEV-ET IBR engineers continually strive to maintain. However, achieving full equilibrium is often challenged by persistent non-conformances resulting from ongoing changes in IBR design updates, evolving DEV-ET requirements, site-specific conditions, and variations in Physical Configurations. In addition to ensuring configuration alignment, the CMCP also serves as a centralized system for collecting and storing IBR attributes. This is especially valuable in DEV-ET, where such data is typically fragmented across multiple departments.

### **4.3 The Configuration Management Triangle Model (CMTM)**

The Configuration Management Triangle Model (CMTM), illustrated in Figure 17, defines the foundational architecture of the CMCP. This model facilitates cross-functional coordination among DEV-ET engineering disciplines to ensure seamless alignment across three critical dimensions:

- **DEV-ET Design Requirements**

The intended equipment and configurations as defined by DEV-ET engineering standards.

- **Design Documentation on File**

The recorded designs, drawings, and approvals reflect what should be installed.

- **Physical Field Conditions**

The actual equipment and configuration verified on-site by Quality Assurance Engineers (QAEs).

CMCP’s purpose is to keep these elements in lockstep—ensuring that what is required, what is documented, and what is installed are consistently matched and up to date. Any misalignment triggers a loss of Configuration Management & Control (CMC), at which point the system must re-enter a corrective state to restore CMCE.

### CONFIGURATION MANAGEMENT TRIANGLE MODEL (CMTM)

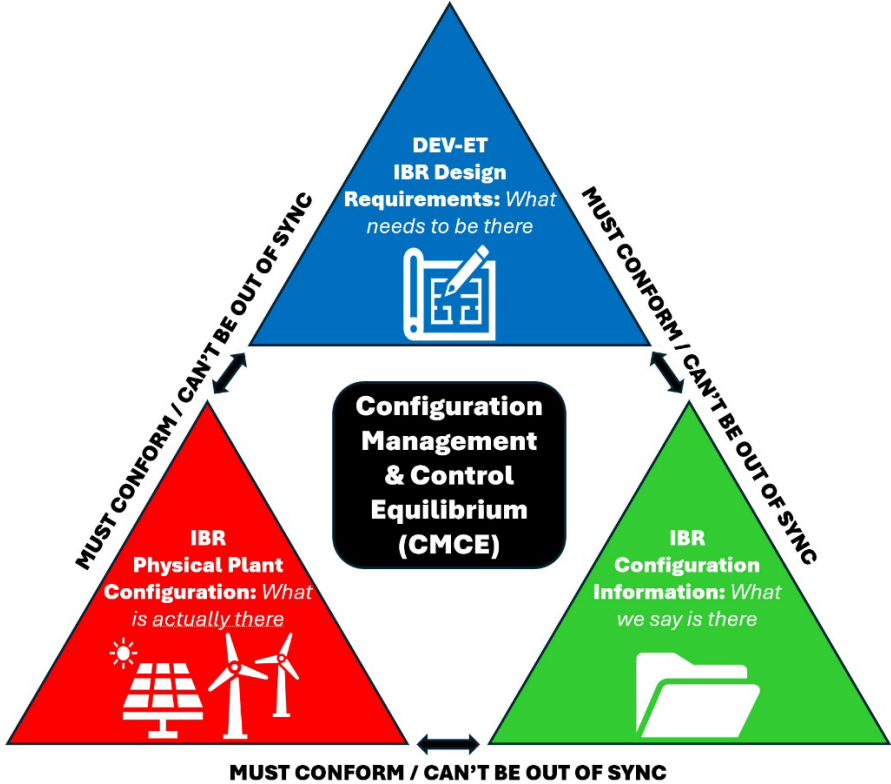



Figure 17. CMTM Model

#### 4.4 IBR Design Requirements (DRs) (What Needs to Be There)

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## CONFIGURATION MANAGEMENT TRIANGLE MODEL (CMTM)

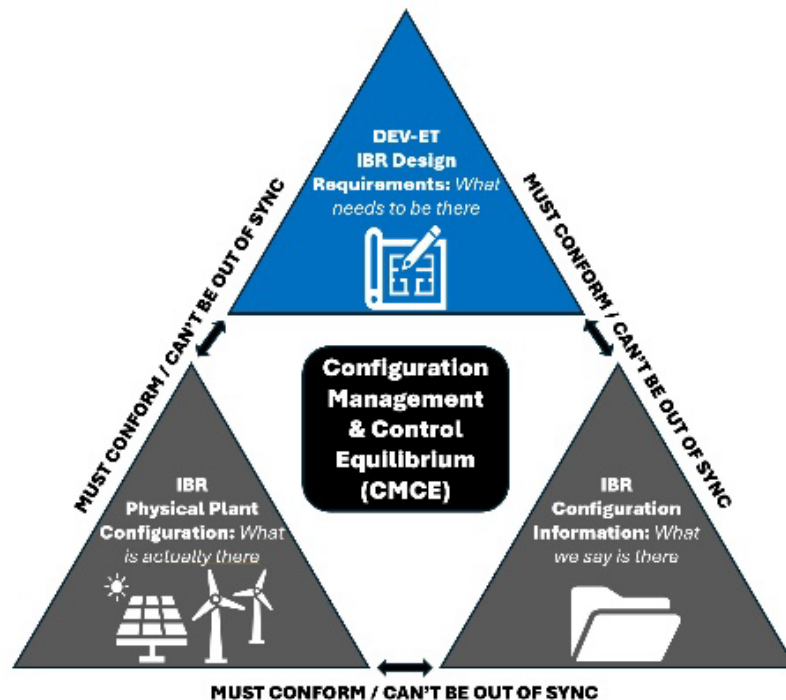


Figure 18. CMTM Requirements


**Design Requirements (DRs)** are DEV-ET-defined technical, modeling, and performance criteria that originate from the IBR design process and are reflected in the final site design. These requirements define the essential characteristics and operational boundaries necessary for the system to function reliably and in compliance with all applicable DEV-ET standards.

Engineers from various DEV-ET departments establish both the **DRs** and the corresponding **Minimum Acceptance Criteria (MAC)** they consider critical for tracking through the **CMCP**. These requirements represent the baseline for what must be present and verifiable to achieve and maintain **CMCE**.

The DRs tracked through CMCP may include, but are not limited to:

- Inverter Settings
- PPC Settings
- Other Digital Equipment Settings
- Installed Equipment
- Modeling Requirements
- Testing Requirements
- Construction Requirements
- Equipment Specification

The identification and tracking of DRs and MAC are essential to the integrity of the CMCP. By clearly defining what needs to be there, DEV-ET engineers ensure that IBR systems are designed, documented, and implemented in a manner that supports safe, reliable, and compliant grid integration. These requirements

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serve as the foundation for achieving CMCE and provide a structured framework for quality assurance across all stages of the DER/IBR lifecycle.

#### 4.5 IBR Configuration Information (CI) (What We Say Is There)

### CONFIGURATION MANAGEMENT TRIANGLE MODEL (CMTM)




Figure 19. CMTM Configuration Information

The second cornerstone of the **Configuration Management Triangle Model (CMTM)** is **Configuration Information (CI)**—the documented representation of how an IBR system is designed and intended to operate. This information defines the functional roles of site equipment, the control parameters applied, and the expected performance characteristics of the final design.

CI is typically distributed across various DEV-ET departments and may exist in multiple formats. It includes both technical documentation and operational records that describe the configuration and behavior of IBR systems. These documents are essential for validating that the system aligns with design intent and DEV-ET standards.

As part of the **CMCP**, efforts are made to collect and consolidate key IBR attributes during the **Site Review (SR)** and **Field Inspections & Verifications (FIV)** phases. This process supports the creation of a centralized database of IBR configuration data, ensuring that critical information is readily available for DEV-ET engineers when needed.

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### Examples of IBR Configuration Information (CI)


The types of documentation that may be considered part of CI include, but are not limited to:

- Design Drawings
- Single Line Diagrams
- Design Specifications
- Testing Requirements
- Modeling Requirements
- Equipment Specifications
- Equipment Manuals
- Programming Reports for Digital Devices
- PPC Narrative Documentation
- SCADA Narrative Documentation
- Transmission Protection Requirements
- Interconnection Request
- Interconnection Agreement
- Interconnection Facilities Study Report
- SIS Report
- Communication Standards
- Technical Procedures
- Operations Procedures
- Control Standards
- Maintenance Records
- Training Documentation

CI plays a critical role in achieving and maintaining **CMCE**. It serves as the authoritative source for what is claimed to be installed and configured at an IBR site. By consolidating and validating this information, DEV-ET engineers can:

- Ensure alignment between design intent and field implementation
- Support compliance with regulatory and operational standards
- Facilitate troubleshooting, maintenance, and future upgrades
- Provide traceability and accountability across engineering disciplines
- Enable efficient data access for audits, reviews, and system planning

In short, CI is the bridge between what is required and what is physically present, making it an essential component of the CMCP framework.

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#### 4.6 IBR Physical Configuration (PC) (What Is Actually There)

### CONFIGURATION MANAGEMENT TRIANGLE MODEL (CMTM)

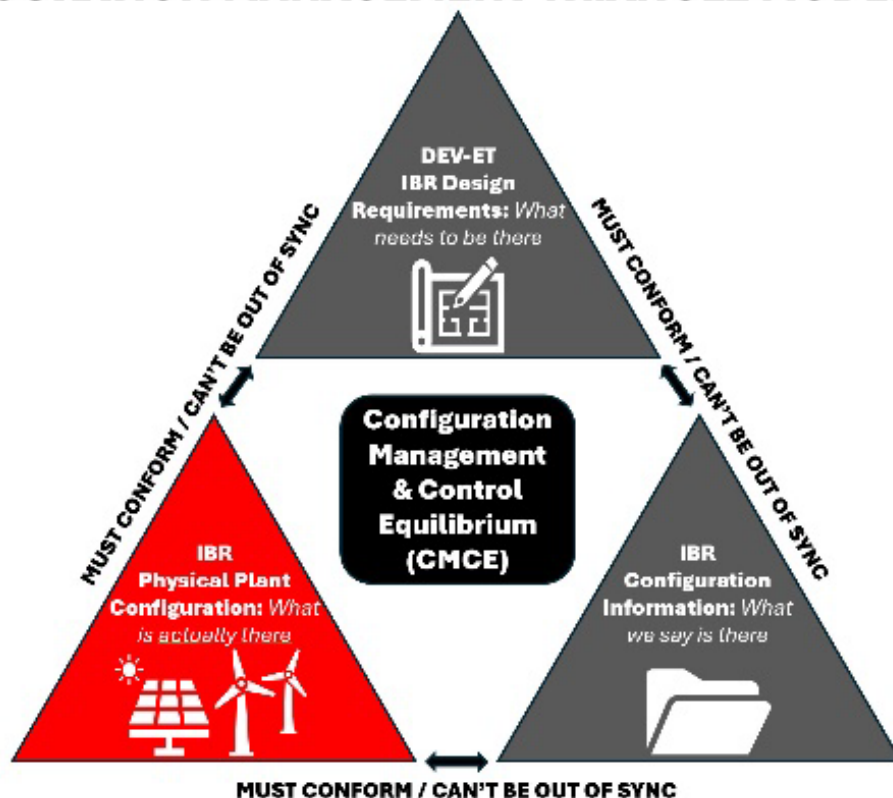


Figure 20. CMTM – Physical Configuration


The third and final cornerstone of the **Configuration Management Triangle Model (CMTM)** is the **Physical Configuration (PC)**, the actual, observable condition, arrangement, and installation of IBR equipment in the field. This component represents the physical reality of the system and serves as the basis for verifying that the site has been built in accordance with both the **DRs** and the documented **CI**.

This function’s main objective is to ensure that any changes or deviations in the PC are identified, documented, and reconciled with the design and documentation records. This verification process is essential for maintaining **CMCE**.

#### Key Activities in Verifying Physical Configuration (PC)

The validation of PC typically includes, but is not limited to, the following activities:

- Conducting **FIV** to confirm the site meets the DEV-ET’s Design and Testing Requirements, as defined by the **MAC**
- Documenting any field discrepancies or deviations from design
- Notifying the appropriate DEV-ET departments of inspection findings
- Collaborating with relevant teams to initiate and implement corrective actions

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- Re-establishing **CMCE** where misalignments are identified
- Adhering to **CMCP procedures** throughout the inspection and resolution process

The **PC** represents the final and most tangible layer of the CMTM. It is the point at which design intent and documentation are tested against real-world implementation. By thoroughly inspecting and validating the physical installation, DEV-ET teams can identify discrepancies, enforce accountability, and ensure that the DER/IBR system is safe, compliant, and ready for operation.

This step is critical in closing the loop between **what is required, what is documented, and what is actually there**—ultimately enabling the successful establishment of **CMCE**.

## 5.0 REFERENCES

- References available on NERC’s website ([www.nerc.com](http://www.nerc.com)):
  - NERC Glossary of Terms
  - NERC Reliability Standards
- References available on PJM’s website ([www.pjm.com](http://www.pjm.com)):
  - PJM Manual 14A: New Services Request Process
  - PJM Manual 14C: Generation and Transmission Interconnection Facility Construction
  - PJM Manual 14D: Generator Operational Requirements
  - PJM Manual 14G: Generation Interconnection Requests
  - PJM Manual 14H: New Service Request Cycle Process
  - PJM Manual 01: Control Center and Data Exchange Requirements
  - PJM Manual 03: Transmission Operations
  - PJM Manual 07: Protection Standards
- References available on IEEE’s website (<https://standards.ieee.org>):
  - IEEE C2-2023, IEEE Standards Association “The National Electrical Safety Code” (NESC)
  - IEEE Std 2800, “IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems”
  - IEEE Std 80, “IEEE Guide for Safety in AC Substation Grounding”
  - IEEE Std C37, IEEE standards related to System Protection
  - IEEE Std C57, IEEE standards related to Transformers
  - IEEE Std 485, “IEEE Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications”
  - ANSI C29 Series: American National Standards Institute (ANSI) C29 series, “Standard for Wet-Process Porcelain Insulators”
  - IEEE Std 62.82.1-2010: Institute of Electrical and Electronics Engineers (IEEE), “IEEE Standard for Insulation Coordination—Definitions, Principles, and Rules”
  - IEEE Std 1453-2015: Institute of Electrical and Electronics Engineers (IEEE), “IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems”
  - IEEE Std 605-2023: Institute of Electrical and Electronics Engineers (IEEE), “IEEE Guide for Bus Design in Air Insulated Substations”
  - IEEE C62 Series: Institute of Electrical and Electronics Engineers (IEEE) C62 series, “IEEE Standards for Surge Protective Devices”



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### 6.0 REVISION HISTORY

**Table 4. 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

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Revision Date	Revision #	Description	Revised By	Effective Date
08/01/2024	23.0	See Details for Revision 23.0 below	Kristen Custer	09/01/2024
03/11/2025	24.0	See Details for Revision 24.0 below	Kristen Custer	04/01/2025
09/10/2025	25.0	See Details for Revision 25.0 below	Kristen Custer	10/01/2025
03/01/2026	26.0	See Details for Revision 26.0 below	Thomas J. McConnell and Danovo Energy Solutions	04/01/2026

**Details for Revision 1.0**

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

**Details for Revision 2.0**

- Revised to reflect the 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 of 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 the emergency rating of the 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.

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- 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 2.13.1 Tapping Line for Loads Below 100 MW 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:

- 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 the applicability of the document.
- Section 3.1.9—Voltage, Reactive Power, and Power Factor Control–Generation Facilities subsection:
  - Revised the first bullet regarding generator control systems.
  - Added a 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 the 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 a 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 the Application Guidelines and Technical Basis of FAC-001-2.
- 3.3.5. Refined discussion of Protection System Design.

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- 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 documents and exhibits.
- Updated approval page per personnel change since the prior version.
- Revised references for the 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–Revenue Metering Data Communications subsection: 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 a new section regarding generation connected to transmission tap lines.
- Section 8.1: Added definition for Transmission Element.
- Made all remaining revisions for Dominion Energy’s 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).

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#### Details for Revision 17.0

- Performed annual review of documents and exhibits.
- Updated approval page per personnel change since the 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).

#### Details for Revision 18.0

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

#### Details for Revision 19.0


- 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.

#### Details for Revision 20.0

- 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, and 7 from Revision 19.0 into Section 4.0–Procedure in this Revision.

#### Details for Revision 21.0

- Updated Signature Page.
- Minor wording update.

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- 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 22.0**

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

#### **Details for Revision 23.0**


- Revision contributors include the following: Aaron Winter, Amirreza Sahami, Andrea Pinceti, Colleen Wallace, Harrison Potter, Ibukunoluwa Korede, Katelynn Vance, Keith Graham, Mark Gill, Nedim Besirevic, Peter Nedwick, Praveen Dhanasekar, YaJun Zheng, Nancy Ashberry, Ronnie Bailey, SooKwon Ha, and Quanta-Technology Services.
- Updated Signature Page to include Managers and Directors from Supporting Document Attachments 1–6.
- Made the Facility Interconnection Requirements a standalone document by removing reference to NERC Compliance Procedure and removing Section 1 and 3.
- Removed Section 1–Purpose. This section describes FAC-001 and DEV’s compliance as it relates to interconnection requirements and is not useful to the interconnection Customer.
- Removed Section 3–Applicability. This section describes DEV’s FAC-001 compliance role and is not useful to the interconnection Customer.
- Moved Acronyms into a table at the beginning of the document to be consistent with industry practices.
- Moved Definitions to the beginning of the document to be consistent with industry practices.
- Moved References to the end of the document to be consistent with industry practices.
- Added Section 3–Option To Build. This chapter was added to alert interconnection Customers to the need to sign an NDA and follow DEV design and construction practices.
- Added Section 4–Project Commissioning. This chapter was added to alert the interconnection Customer to the project owner’s reliability responsibility and the need to keep DEV informed of the plant’s control settings. This chapter includes a reference to a future Configuration Management Program (CMP).
- Added Attachment 6—Technical Requirements for Generation Interconnection Substations.
- Revised Attachment 2—Customer Request Form.
- Renumbered figures to match formatting.
- Renamed Section 2.1 (was 4.2.1.1) from “Data Required to Properly Study the Interconnection” to “Required Simulation Data.” This is more concise.
- Added language, with footnotes, to Section 2.1 (was 4.2.1.1) to include IBR EMT models and the need for interconnection Customers to keep their EMT model updated.
- Removed table showing voltages from Section 2.2 (was 4.2.2) “Voltage level and MW and MVar Capacity or demand at the POI.” This information is in other locations.
- Edited language in Section 2.3 (was 4.2.3) to be more understandable.
- Updated headings in the table found in Section 2.3 (was 4.2.3) to match industry-defined terminology.
- Added a bullet to the list in Section 2.3 to alert the interconnection Customer to unique IBR design requirements.
- Added language to Section 2.4 (was 4.2.4) to make the requirement more understandable.
- Added Section 2.4.1.1, “Inverter-based Resource (IBR) Protection Systems.”

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- Added language to Section 2.6 (was 4.2.6) to refer developers to the IEEE Guide for Solar Power Plant Grounding for Personal Protection.
- Change the voltage table headers in Section 2.7 (was 4.2.7) to match industry definitions.
- Added additional references added to References section.
- Added a bullet to Section 2.8.1 (was 4.2.8.1) to account for FERC synchronous and non-synchronous generator power factor requirements.
- Added reference to IEEE Standard in Section 2.9.1 (was 4.2.9.1) Flicker Requirements.
- Change the voltage table headers in Section 2.10 (was 4.2.10), Equipment Ratings, to match industry definitions.
- Added Section 2.12.4–Isolation Device. This was added to be more specific about the type of isolation device used between DEV and the interconnection Customer.

#### **Details for Revision 24.0**

- Revision contributors include the following: Daniel Ridenour, Andrea Pinceti, Candace Marshall, Jonathan Deverick, Aaron Trump, Ibukunoluwa Korede, Donnie Wilkerson, Mike Yunik, Nedim Besirevic, Katelynn Vance, Kristen Custer, Keith Graham, and Quanta Technology.
- Document formatting (fonts, margins, etc.) updated to improve readability. Changed the main font from Arial to Aptos.
- Updated Abbreviations and Acronyms
- Resized all figures and improved quality.
- Renumbered figures to match formatting.
- Grammatical modifications including capitalization, spelling, punctuation, and consistency.
- Revised Section 1.0 to clarify that all new interconnections and Qualified Changes to existing interconnections must follow PJM Manual 14b, Section G.12.
- Renamed all section titles and contents that included the word “Modifications” to “Qualified Change(s).”
- Added language in Section 1.1 to explicitly require notification of interconnection modifications that impact system reliability.
- Added section 1.3, Procedure for Confirming Facility Location within the BA.
- Added language to clarify interconnection simulation data requirements to include the EMT and to support benchmarking requirements for models. Clarified that customers must update their EMT models post-commissioning as part of NERC MOD-26 and MOD-27 compliance.
- Clarified customer responsibilities toward breaker duty and protection in Section 2.3
- Renamed Section 2.3.1.1 from Inverter-Based Resource to IBR.
- Clarified IEEE Std 2800 to reference the 2022 version.
- Added Section 2.4.1.5 on load ride-through requirements, recommending best practices for customers.
- Added language in Section 2.6 to clarify tapped transformer interconnections
- Added clarifying language to Section 2.8.1 to describe reactive power performance expectations of IBRs.
- Modified Section 2.9 to reflect compliance expectations around the IEEE Std 2800-2022 for flicker, harmonics, and inter-harmonics.
- Added language to Section 2.11 to clarify requirements before synchronization of facilities.
- Added language to Section 2.11.6 to establish cadence around contact information requirements for maintenance personnel.
- Added language to Section 2.11.7 to clarify customer obligations and expectations toward providing advance notices.
- Added language to Section 2.12 prohibiting future facilities from forming multi-terminal lines.
- Removed all references to radial transmission tap formation, including removing Figure 5 and Figure 6.

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- Added clarifying language in Section 2.12.6 to describe scenarios where additional circuit breakers might be required.
- Added clarifying language in Section 2.13 on the role of DEV-ET in planning analysis, factors to be considered before agreeing on customer connections, design configurations for line tap, prohibiting designs including radial transmission tap formation, and expectations around data submittals for end-use facilities.
- Added language in Sections 2.13.1 and 2.13.2 on the expected design attributes of System Protection by Interconnection Customers.
- Added language in Section 3.2 around Customer costs incurred and expectations while selecting Option to Build.
- Renamed Section 4 from “Project Commissioning” to “Project Enter Service Commissioning.”
- Modified the language in Section 4 to describe the Change Management Program (CMP), Witness Testing Program (WTP), and IBR field inspection program, clarify commissioning responsibilities between Interconnection Customers and DEV-ET, and establish roles and responsibilities.
- Updated References to include IEEE Std 62.82.1-2010,1453-2015,605-2023, C62 Series, and ANSI C29.

**Details for Revision 25.0**

- Revision contributors include the following: Daniel Ridenour, Maxwell Danku, Christina Vaughan, Nancy Ashberry, Ibukunoluwa Korede, Donnie Wilkerson, Nedim Besirevic, Katelynn Vance, Kristen Custer, Keith Graham, and Quanta Technology.
- General editorial and formatting updates.
- Added new acronyms and updated definitions.
- Added new attachment 7 ( IBR modeling) and attachment 8 (Large load interconnection requirements)
- Expanded simulation/modeling requirements – EMT models, benchmarking, and validation.
- Strengthened protection requirements – IBR protection, dual primary, breaker failure, DC supply backup.
- Added PEILL (large load) ride-through requirements.
- Updated metering/telecom – tighter accuracy, redundancy, UTC sync.
- Transmission: banned multi-terminal lines, removed radial taps, added breaker “C”.
- End-user loads: clarified limits, added PEILL obligations.
- Option to Build – NDA and inspections clarified.
- Project Commissioning: replaced CMP with new ESC framework (CMCP + WTP).
- References updated with latest IEEE/ANSI standards.

**Details for Revision 26.0**


- Added revised Attachment 7 (IBR modeling) and Attachment 8 (large load interconnection requirements).
- Added clarifying language to Attachment 1 on generator dispatch.
- Basic editorial for grammar, formatting, and consistency.

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# Attachment 1


## Planning Criteria

### Dominion Energy Virginia—Electric Transmission Facility Interconnection Requirements

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## ABBREVIATIONS AND DEFINITIONS

Term	Definition
<b>3Ø</b>	Three-phase
<b>AAR</b>	Auction Revenue Rights (see PJM Manual 06 – Financial Transmission Rights for more details)
<b>ANSI</b>	American National Standards Institute
<b>BES</b>	Bulk Electric System
<b>D/B/A</b>	Doing Business As
<b>DEV</b>	Dominion Energy Virginia
<b>DEV-ET</b>	Dominion Energy Virginia Electric Transmission
<b>EHV</b>	Extra-high Voltage
<b>EMT</b>	Electromagnetic Transient
<b>ERAG</b>	Eastern Interconnection Reliability Assessment Group
<b>ERO</b>	Electric Reliability Organization
<b>FACTS</b>	Flexible AC Transmission System
<b>FCITC</b>	First Contingency Incremental Transfer Capability
<b>FIR</b>	Facilities Interconnection Requirements
<b>GDC-17</b>	General Design Criterion 17
<b>GIA</b>	Generation Interconnection Agreement
<b>Good Utility Practice</b>	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.
<b>GSU</b>	Generator Step-up Transformer
<b>HV</b>	High Voltage
<b>IEEE</b>	Institute of Electrical and Electronics Engineers
<b>IPO</b>	Independent Pole-operated
<b>ISA</b>	Interconnection Service Agreement
<b>LD</b>	Load Dump
<b>MMWG</b>	Multi-Regional Modeling Working Group
<b>N</b>	Normal Rating
<b>NERC</b>	North American Electric Reliability Corporation
<b>NPIR</b>	Nuclear Plant Interface Requirements
<b>NRC</b>	Nuclear Regulatory Commission
<b>PJM</b>	PJM Interconnection, LLC
<b>POI</b>	Point of Interconnection
<b>PRC</b>	Protection and Control
<b>PSS</b>	Power System Stabilizer
<b>RAS</b>	Remedial Action Schemes
<b>RCP</b>	Reactor Coolant Pump
<b>RRO</b>	Regional Reliability Organization
<b>RTEP</b>	Regional Transmission Expansion Plan
<b>RTO</b>	Regional Transmission Organization

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Term	Definition
<b>SERC</b>	SERC Reliability Corporation
<b>SIS</b>	System Impact Study
<b>SLG</b>	Single-line-to-ground
<b>STE</b>	Short-term Emergency
<b>TO</b>	Transmission Owner
<b>TP</b>	Transmission Planner
<b>TPL</b>	Transmission Planning
<b>UCSA</b>	Upgrade Construction Service Agreement
<b>UFLS</b>	Under-Frequency Load Shedding

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## 1.0 SCOPE AND OBJECTIVE

The function of the Transmission System is to transport power from generating resources to distribution systems to serve the demands 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 doing business as (d/b/a) Dominion Energy Virginia (DEV). In this document, “DEV-ET” refers to the electric Transmission System owned by DEV. “Transmission System” refers to networked and radial Facilities within the DEV-ET system at voltage levels of 69 kV, 115 kV, 138 kV, 230 kV, and 500 kV. This document provides approved criteria upon which the needs for reinforcements and enhancements to the DEV-ET are determined.

DEV-ET’s criteria ensure 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 six regional reliability organizations (RRO) of NERC. Unless noted, the criteria in this document apply to generation, transmission, and end-user Facilities.

## 2.0 STANDARDS, GUIDES, AND CRITERIA USED FOR TRANSMISSION PLANNING

### 2.1 NERC Transmission Planning Standards and Documents

NERC was established to promote the reliability of bulk electric systems (BES) and is the Electric Reliability Organization (ERO) for North America. NERC develops and enforces reliability standards, including transmission planning standards, to ensure the reliable operation of the interconnected BESs. The NERC transmission planning standards can be found on the NERC homepage (<https://www.nerc.com>). NERC also publishes guidelines, standardized data, and special requirements to aid transmission planners (TP). A list of relevant NERC documents can be found in the References section of this document.

### 2.2 Regional Transmission Planning Standards


NERC consists of six regional reliability organizations. DEV-ET is a member of SERC, one of the six regional reliability organizations. DEV-ET plans its portion of the BES in coordination with its TP, PJM, to meet the requirements of NERC and SERC.

### 2.3 PJM Transmission Planning Standards

The DEV-ET is integrated into the planning and operations of the PJM Interconnection, LLC (PJM) Regional Transmission Operator (RTO). 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 enhancements. The criteria PJM uses in developing the RTEP are set forth in PJM Manual 14B–PJM Region Transmission Planning Process.

### 2.4 IEEE Industry Standards

The Institute of Electrical and Electronics Engineers (IEEE) has not developed performance standards for planning transmission. Instead, Transmission System performance standards have been developed by NERC and the regional entities. Instead, IEEE members have created useful equipment and practice standards that can be used to aid in the transmission planning process. A list of useful IEEE standards is found in the Reference section of this document.

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## 2.5 Coordinated Studies

The studies detailed within Section 1 of the FIR are coordinated with PJM, the TP, the Planning Coordinator, and the affected system(s) that evaluate the impact of new or existing interconnections seeking to make a qualified change. DEV-ET ensures that those responsible for the reliability of affected systems are notified of new interconnections and other qualified changes to an existing interconnection through participation in regional and subregional working groups and committees. This is achieved via coordinated study processes under Inter-Area Reliability Agreements with neighboring utilities. DEV-ET engages with entities such as SERC, the Eastern Interconnection Reliability Assessment Group (ERAG), and the Multi-Regional Modeling Working Group (MMWG), where study results are shared with the appropriate working groups, committees, and task forces. By participating in these collaborative processes, responsible parties remain informed and actively involved in system reliability assessments and planning. PJM ensures that all new or modified Facilities seeking interconnection within its system are assessed under its interconnection process, as outlined in PJM Compliance Bulletin CB028 (NERC Std FAC-001). External entities requesting interconnection must go through this process, during which DEV-ET reviews and comments on draft agreements provided by PJM. Once finalized and signed by the Interconnection Customer, DEV-ET, and PJM, approved projects receive an Interconnection Service Agreement (ISA), Upgrade Construction Service Agreement (UCSA), or Generation Interconnection Agreement (GIA), which is submitted to FERC for approval. After approval, PJM files the agreement and provides a copy to DEV-ET, with public access available via the PJM “Planning” website under “Service Request Status.” A PJM-issued ISA, UCSA, or GIA serves as confirmation that the Facility is within the PJM Balancing Authority Area.

## 3.0 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, studies must be made in advance to identify the Facilities necessary to ensure 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.


Table 1 and Table 2 specify outage events that are analyzed by DEV-ET 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-ET 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.<sup>1</sup>
- Load tap changer adjustment.
- Shunt and series capacitor bank switching.

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<sup>1</sup> For DEV, phase angle regulator adjustment might be used to relieve loadings on the 115 kV 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 Regional Transmission Planning Process (RTEP Reliability Planning section).

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- Line switching.
- Shunt and series reactor switching.
- Adjustment of Flexible AC Transmission System (FACTS) devices.

DEV-ET Facilities loaded over their normal rating, following a contingency, must be adjusted to the Facility’s normal rating or below within the time limit given for the short-term emergency rating. Any of the above-listed system readjustments are allowable in this situation as DEV-ET employs an 8-hour short-term emergency rating on transmission equipment. This allows sufficient time to implement any adjustments needed to 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 simulating real-world conditions where a fault takes an entire line out of service (breaker-to-breaker) as the first contingency. The second contingency involves simulating a breaker-to-breaker outage on another Transmission element while the initial fault remains isolated.

If the criteria described in this document cannot be met, a Corrective Action Plan<sup>2</sup> will be developed. The Corrective Action 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 (RAS), or the installation of a physical reinforcement.

An 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. An 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 012–017. An RAS does not include automatic restoration to service of unfaulted 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-ET reviews all existing RASs periodically and adjusts settings as deemed necessary. DEV-ET will normally install an RAS as a temporary measure until a more robust solution can be completed to provide acceptable system performance. Operating steps implemented as part of an RAS shall be considered, provided that the failure of such a system does not result in cascading outages or overloads.

In addition to those events and circumstances included Table 1 and Table 2, Table 3 defines more severe but less probable scenarios that should also be considered for analysis to evaluate the resulting consequences. As permitted in the NERC Planning Standards, judgment shall dictate whether and to what extent a mitigation plan would be appropriate.

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<sup>2</sup> NERC’s Glossary of Terms defines a Corrective Action Plan as “A list of actions and an associated timetable for implementation to remedy a specific problem.”



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**Table 1. Steady-state Performance: Planning Events and Dominion Energy Criteria for High Voltage Facilities (230 kV, 138 kV, 115 kV, and 69 kV)**

NERC TPL-001 Events (Excludes DC)						Dominion Energy Criteria				
Category	Initial Condition	Event <sup>1</sup>	Fault Type <sup>2</sup>	Interruption of Firm Transmission Service Allowed <sup>4</sup>	Non-consequential Load Loss Allowed <sup>*</sup>	Thermal Limits	Low Voltage Limit <sup>**</sup>	High Voltage Limit <sup>**</sup>	Volt Drop (< 230 kV)	Volt Drop (230 kV)
<b>P0</b> No Contingency	Normal system	None	N/A	No	No	94% N	95%	105% and 103%	N/A	N/A
<b>P1</b> Single Contingency	Normal system	Loss of one of the following: 1. Generator 2. Transmission circuit 3. Transformer <sup>5</sup> 4. Shunt device <sup>6</sup>	3Ø	No <sup>9</sup>	No <sup>12</sup>	94% STE	93%	105% and 103%	10%	8%
<b>P2</b> Single Contingency	Normal system	1. Opening of a line section without a fault <sup>7</sup>	N/A	No <sup>9</sup>	No <sup>12</sup>	94% STE	93%	105% and 103%	10%	8%
		2. Bus section fault	SLG	Yes	Yes	100% STE	90%	105% and 103%	10%	8%
		3. Internal breaker fault <sup>8</sup> (non-bus-tie breaker)	SLG	Yes	Yes	100% STE	90%	105% and 103%	10%	8%
		4. Internal breaker fault (bus-tie breaker) <sup>8</sup>	SLG	Yes	Yes	100% STE	90%	105% and 103%	10%	8%
<b>P3</b> Multiple Contingencies (See Dominion Energy Notes “A,” “B,” and “C”)	Loss of generator unit followed by system adjustments <sup>9</sup>	Loss of one of the following: 1. Generator 2. Transmission circuit 3. Transformer <sup>5</sup> 4. Shunt device <sup>6</sup>	3Ø	No <sup>9</sup>	No <sup>12</sup>	94% STE	93%	105% and 103%	10%	8%



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NERC TPL-001 Events (Excludes DC)						Dominion Energy Criteria				
Category	Initial Condition	Event <sup>1</sup>	Fault Type <sup>2</sup>	Interruption of Firm Transmission Service Allowed <sup>4</sup>	Non-consequential Load Loss Allowed*	Thermal Limits	Low Voltage Limit **	High Voltage Limit **	Volt Drop (< 230 kV)	Volt Drop (230 kV)
<b>P4</b> Multiple Contingencies ( <i>Fault Plus Stuck Breaker<sup>10</sup></i> ) (See Dominion Energy Note "B")	Normal system	Loss of multiple elements caused by a stuck breaker <sup>10</sup> (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer <sup>5</sup> 4. Shunt device <sup>6</sup> 5. Bus section 6. Loss of multiple elements caused by a stuck breaker <sup>10</sup> (bus-tie breaker) attempting to clear a Fault on the associated bus	SLG	Yes	Yes	100% STE	90%	105% and 103%	10%	8%
<b>P5</b> Multiple Contingencies ( <i>Fault Plus Relay Failure to Operate</i> ) (See Dominion Energy Note "B")	Normal system	Delayed fault clearing due to the failure of a non-redundant component of a protection system <sup>13</sup> protecting the faulted element to operate as designed for one of the following: 1. Generator 2. Transmission circuit 3. Transformer <sup>5</sup> 4. Shunt device <sup>6</sup> 5. Bus section	SLG	Yes	Yes	100% STE	90%	105% and 103%	10%	8%
<b>P6</b> Multiple Contingencies ( <i>Two Overlapping Singles</i> ) (See Dominion Energy Notes "B" and "C")	Loss of one of the following followed by system adjustments: <sup>9</sup> 1. Transmission circuit 2. Transformer <sup>5</sup> 3. Shunt device <sup>6</sup>	Loss of one of the following: 1. Transmission circuit 2. Transformer <sup>5</sup> 3. Shunt device <sup>6</sup>	3Ø	Yes	Yes	100% STE	90%	105% and 103%	10%	8%

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Category	Initial Condition	Event <sup>1</sup>	Fault Type <sup>2</sup>	Interruption of Firm Transmission Service Allowed <sup>4</sup>	Non-consequential Load Loss Allowed*	Thermal Limits	Low Voltage Limit **	High Voltage Limit **	Volt Drop (< 230 kV)	Volt Drop (230 kV)
<b>P7</b> Multiple Contingencies (Common Structure)	Normal system	The loss of any two adjacent (vertically or horizontally) circuits on a common structure <sup>11</sup>	SLG	Yes	Yes	100% STE	90%	105% and 103%	10%	8%

**Dominion Energy Notes for Table 1**

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

- Note "A": See Section 2.1.3 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 the 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: A lower overvoltage limit of 103% is applied to 138 kV Facilities based on the age and number of legacy switches on the network at this voltage. Be aware that voltage limits for the North Anna and Surry power stations are governed by the requirements of their respective Nuclear Plant Interface Requirements (NPIR) with DEV-ET, as noted in Section 3.
- N: Normal rating.
- STE: Short-term emergency.
- LD: Load dump.

**Table 2. Steady-state Performance Planning Events and Dominion Energy Criteria for Extra-high Voltage Facilities (500 kV)**

NERC TPL-001 Events (Excludes DC)						Dominion Energy Criteria			
NERC Category	Initial Condition	Event <sup>1</sup>	Fault Type <sup>2</sup>	Interruption of Firm Transmission Service Allowed <sup>4</sup>	Non-consequential Load Loss Allowed*	Thermal Limits	Low Voltage Limit **	High Voltage Limit **	Volt Drop
<b>P0</b> No Contingency	Normal system	None	N/A	No	No	94% N	102.5%	108%	N/A



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NERC TPL-001 Events (Excludes DC)						Dominion Energy Criteria			
NERC Category	Initial Condition	Event <sup>1</sup>	Fault Type <sup>2</sup>	Interruption of Firm Transmission Service Allowed <sup>4</sup>	Non-consequential Load Loss Allowed <sup>*</sup>	Thermal Limits	Low Voltage Limit <sup>**</sup>	High Voltage Limit <sup>**</sup>	Volt Drop
<b>P1</b> Single Contingency	Normal system	Loss of one of the following: 1. Generator 2. Transmission circuit 3. Transformer <sup>5</sup> 4. Shunt device <sup>5</sup>	3Ø	No <sup>9</sup>	No <sup>12</sup>	94% STE	101%	109.6%	6%
<b>P2</b> Single Contingency	Normal system	1. Opening of a line section without a fault <sup>7</sup>	N/A	No <sup>9</sup>	No <sup>12</sup>	94% STE	101%	109.6%	6%
		2. Bus section fault	SLG	No <sup>9</sup>	No	100% STE	100%	109.6%	6%
		3. Internal breaker fault <sup>8</sup> (non-bus-tie breaker)	SLG	No <sup>9</sup>	No	100% STE	100%	109.6%	6%
		4. Internal breaker fault (bus-tie breaker) <sup>8</sup>	SLG	Yes	Yes	100% STE	100%	109.6%	6%
<b>P3</b> Multiple Contingencies (See Dominion Energy Notes “D,” “E,” and “F”)	Loss of generator unit followed by system adjustments <sup>9</sup>	Loss of one of the following: 1. Generator 2. Transmission circuit 3. Transformer <sup>5</sup> 4. Shunt device <sup>5</sup>	3Ø	No <sup>9</sup>	No <sup>12</sup>	94% STE	101%	109.6%	6%
<b>P4</b> Multiple Contingencies ( <i>Fault Plus Stuck Breaker</i> <sup>10</sup> ) (See Dominion Energy Note “D”)	Normal system	Loss of multiple elements caused by a stuck breaker <sup>10</sup> (non-bus-tie breaker) attempting to clear a fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer <sup>5</sup> 4. Shunt device <sup>6</sup> 5. Bus section	SLG	No <sup>9</sup>	No	100% STE	100%	109.6%	6%
		6. Loss of multiple elements caused by a stuck breaker <sup>10</sup> (bus-tie breaker) attempting to clear a fault on the associated bus	SLG	Yes	Yes	100% STE	100%	109.6%	6%



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NERC TPL-001 Events (Excludes DC)						Dominion Energy Criteria			
NERC Category	Initial Condition	Event <sup>1</sup>	Fault Type <sup>2</sup>	Interruption of Firm Transmission Service Allowed <sup>4</sup>	Non-consequential Load Loss Allowed <sup>*</sup>	Thermal Limits	Low Voltage Limit <sup>**</sup>	High Voltage Limit <sup>**</sup>	Volt Drop
<b>P5</b> Multiple Contingencies <i>(Fault Plus Relay Failure to Operate)</i> (See Dominion Energy Note “D”)	Normal system	Delayed fault clearing due to the failure of a non-redundant component of a protection system <sup>13</sup> protecting the faulted element to operate as designed for one of the following: 1. Generator 2. Transmission circuit 3. Transformer <sup>5</sup> 4. Shunt device <sup>6</sup> 5. Bus section	SLG	No <sup>9</sup>	No	100% STE	100%	109.6%	6%
<b>P6</b> Multiple Contingencies <i>(Two Overlapping Singles)</i> (See Dominion Energy Notes “D” and “F”)	Loss of one of the following followed by system adjustments. <sup>9</sup> 1. Transmission circuit 2. Transformer <sup>5</sup> 3. Shunt device <sup>6</sup>	Loss of one of the following: 1. Transmission circuit 2. Transformer <sup>5</sup> 3. Shunt device <sup>6</sup>	3Ø	Yes	Yes	100% STE	100%	109.6%	6%
<b>P7</b> Multiple Contingencies <i>(Common Structure)</i>	Normal system	The loss of any two adjacent (vertically or horizontally) circuits on a common structure <sup>11</sup>	SLG	Yes	Yes	100% STE	100%	109.6%	6%
<b>Dominion Energy Notes for Table 2</b>									
See separate listing <i>Table 2 (A and B) Footnotes</i> for superscript numbered footnotes.									
<ul style="list-style-type: none"> <li>Note “D”: See Section C.2.1.3 for details.</li> <li>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.</li> <li>Note “F”: System adjustments should be performed after the first contingency event (Initial Condition).</li> <li>If the aggregated consequential or non-consequential load loss exceeds 300 MW, system reinforcements will be required.</li> <li>** Percent of Nominal Voltage: Be aware that voltage limits for the North Anna and Surry power stations are governed by the requirements of their respective NPIR with DEV-ET, as noted in Section E.3.</li> <li>N: Normal rating.</li> <li>STE: Short-term emergency.</li> <li>LD: Load dump.</li> </ul>									



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**Table 3. 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 **	
<b>N-2</b> 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 prior to System adjustments.	YES	YES	100% LD	90%	Note "M"	
<b>LAE</b> Local Area Events	a. Loss of a tower line with three or more circuits <sup>11</sup> .	YES	YES	100% LD Note "H"	90%	Note "M"	
	b. Loss of all transmission lines on a common right-of-way <sup>11</sup> .	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"	
<b>WAE</b> Wide-area Events	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"	

**Dominion Energy Notes for Table 3**

See separate listing *Table (1, 2, and 3) Footnotes* for superscript numbered footnotes.



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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 **				
	<ul style="list-style-type: none"> <li>• Note "G": For all extreme events evaluated:               <ul style="list-style-type: none"> <li>▪ Simulate the removal of all elements that protection systems and automatic controls are expected to disconnect for each contingency.</li> <li>▪ Simulate normal clearing unless otherwise specified.</li> </ul> </li> <li>• Note "H": The loss of 3 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.</li> <li>• 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.</li> <li>• Note "J": The loss of a switching station or substation (1 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.</li> <li>• 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).</li> <li>• 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).</li> <li>• Note "M": High voltage is 105%, and extra-high voltage is 109.6%.</li> <li>• ** Percent of Nominal Voltage: Be aware that voltage limits for the North Anna and Surry power stations are governed by the requirements of their respective NPIR with DEV-ET, as noted in Section E.3.</li> <li>• N: Normal rating.</li> <li>• STE: Short-term emergency.</li> <li>• LD: Load dump.</li> </ul>									

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Tables 1, 2, and 3 footnotes for NERC Reliability Standard TPL-001:

NERC Reliability Standard TPL-001 footnotes for Table 1, Table 2, and Table 3 are as follows:

1. If the event analyzed involves bulk electric system (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 (3 $\emptyset$ ) are the fault types that must be evaluated in stability simulations for the event described. A 3 $\emptyset$  or a double-line-to-ground fault study indicating the criteria are being met is sufficient evidence that an SLG condition would also meet the criteria.
3. BES-level references include extra-high voltage (EHV) Facilities defined as greater than 300 kV and high voltage (HV) Facilities defined as 300 kV 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 applies to the BES-connected voltage (high-side of the generator step-up transformer). Requirements that are applicable to transformers also apply to variable frequency transformers and phase-shifting transformers.
6. Requirements that are applicable to shunt devices also apply to FACTS devices that are connected to the 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 a 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”). 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 used 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

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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, a non-redundant component of a protection system to consider is as follows:
  - a. A single protective relay that 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 the 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).

### **3.1 Voltage Limits at Generating Stations**

Plant auxiliary power equipment requires adequate voltages to maintain the operation of online generators as well as to provide startup capability for offline generators. Minimum transmission voltages at generating stations ensure plant auxiliary equipment will have adequate voltage during both online and offline operation. These voltage limits apply to all classes of generation except wind turbines and photovoltaic (PV) arrays.

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 transformer unit (GSU) are established as 0.95 per unit (minimum) and 1.05 per unit (maximum) unless otherwise specified by the generator owner.

### **3.2 Detailed Steady-state Criteria**


#### **3.2.1 System Load Level**

##### **3.2.1.1 Peak Period Studies**

The peak load period must be studied by DEV-ET 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.

##### **3.2.1.2 Off-peak Period Studies**

DEV-ET 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

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conditions affecting hydro generation plant availability and its impact on the Transmission System are also studied.

### 3.2.1.3 Critical Stress Case Development and Studies

DEV-ET studies the Transmission System under both normal and critical system stress conditions. For NERC Category P3 analysis, DEV-ET 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 offline, and the remaining generators connected to the DEV-ET system are proportionally increased to make up for the lost generation. If there are not enough generation resources available within the DEV-ET system, or the use of DEV-ET generation resources would not provide an adequate base case, then PJM generation resources should be used to make up for any generation deficiency. This resulting critical stress case is then analyzed for NERC compliance based on the transmission contingency events listed in Table 1 and Table 2's Category P3 (Multiple Contingencies).

### 3.2.2 Power Transfers

All studies should consider known firm power transfers affecting the DEV electric 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-ET 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 RTEP process to determine whether the system can accommodate these transfers. The DEV electric 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.<sup>3</sup> SERC also performs transfer limit testing to test the strength of the Transmission System. The results of these studies may also indicate a need to increase the transfer strength of the DEV-ET system.


DEV-ET routinely tests the capability of the Transmission System to transfer reasonable amounts of power (approximately 2,000 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 1 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 decrease the First Contingency Incremental Transfer Capability (FCITC) for transfers between utilities. An FCITC decrement in excess of 5% will be considered significant in most cases.

### 3.2.3 Equipment Ratings

Ratings for transmission Facilities are maintained by DEV-ET and documented in an equipment ratings database. In most cases, equipment is assigned a normal continuous rating and one emergency rating of limited duration. This is not always the case. Some equipment is assigned a normal continuous rating and

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<sup>3</sup>Based on DEV criteria for generation deliverability, the thermal thresholds for No contingency (NERC P0 category) are 94% of normal rating, 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.

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multiple emergency ratings with different durations. The different emergency ratings are referred to as short-term, long-term, and load dump.

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

### 3.2.4 Circuit Breaker Capability

Short circuit analysis is performed to determine the maximum current that circuit breakers will be required to interrupt. All circuit breakers must be able to interrupt the currents determined by short circuit analyses. Likewise, circuit breakers must be able to carry the maximum continuous current found with power flow analysis.

### 3.2.5 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 (static VAR compensators, etc.).


The DEV-ET system is planned so that transmission voltages will be maintained within an acceptable range for Normal and Emergency Conditions, as described in Table 1 and Table 2.

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 Table 1 and Table 2. Distribution Facilities that 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.

### 3.2.6 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 the 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).

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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 the same transmission substation source.
- Normally open network or loop transmission source.

### **3.2.7 Critical Transmission Lines**

A transmission line segment shall be classified as critical if it meets either of the following criteria:

- It operates or is projected to operate at greater than 1,200 A under base case conditions or in a five-year forecast.
- It serves as the single transmission path from a BES generation facility to the broader BES network.

### **3.2.8 Network Transmission Lines: Limitations on Direct-connect Loads**

A “network transmission line” is defined as one that connects two network transmission sources (connects to other lines and substations), and a “tap point” is defined as a direct connection of a Customer to a network transmission line without the 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 kV, 230 kV, 138 kV, 115 kV, and 69 kV lines are considered transmission, and with the exception of 500 kV and Critical Transmission Lines (as defined in Section 3.2.7), all could be tapped to serve Customer load.

Tapped load on any eligible network transmission line is subject to both of the following limits: (1) a maximum of four direct-connect (tapped) facilities, and (2) a total aggregate tapped load not exceeding 300 MW at unity power factor (PF = 1.0). The more restrictive of these two limits shall apply.

The number of direct-connect loads (tapped facilities) is limited to four.


### **3.2.9 Substation: Limitation on Direct-connect Loads**

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

### **3.2.10 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 the end of life is recognized, in order to ensure the 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 Practices and Dominion Energy Transmission Planning Criteria. The

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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. The Facility is nearing, or has already passed, its end of life.
2. Continued operation risks negatively impacting the 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 assessment in the following subsections.

#### 3.2.10.1 End of Life

Factors that support a determination that a Facility has reached its end of life include, but are not limited to, the following:

- The condition of the Facility: This takes into consideration the following:
  - 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 that the Facility has reached the end of its useful service life.


#### 3.2.10.2 Reliability and System Impact

The reliability impact of the 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 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 are not limited to, the following:

1. Market efficiency.
2. Stage 1A ARR sufficiency.
3. Public policy.
4. SERC reliability criteria

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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.

### 3.3 Generation Dispatch Used in DEV-ET Power Flow Studies

The PJM RTEP power flow case for the year under study is the starting point for DEV-ET 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-ET’s analysis to support PJM’s RTEP study process. These modifications may include the following:


- Generating units that have significant environmental limitations, which severely limit the unit’s availability in real-time operation, may be modeled as being offline.
- Generating units that rely on the weather and time of day for operation (PV, WT, hydro) may be modeled offline or at a reduced output to match the conditions being studied.
- Generating units that have been identified in DEV-ET’s IRP filings in Virginia/North Carolina as being “potential” generation retirements may be modeled as being offline.
- Known outages of a generating unit that are consistent with NERC Reliability Standard TPL-001 selection criteria may be modeled as being offline.

The base power flow dispatch provided to DEV-ET in a power flow case, which is used to analyze the reliability impact (Feasibility Study/System Impact Study [SIS]) of generators in the PJM Generation Queue, is typically modified by DEV-ET. Since the case provided to DEV-ET typically has all queue generation located on the DEV-ET system as being offline, DEV-ET will modify the generation dispatch for power flow studies. Specifically, it will turn on all higher-order queue generators and 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 proportionally re-dispatched to account for this additional generation.

Per NERC power flow case quality metrics,<sup>4</sup> the following rules must be respected when developing a generation dispatch:

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<sup>4</sup> NERC 2020 Case Quality Metrics Assessment, October 2020.

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- Generators must not be dispatched outside the generators’ real power MW capabilities.

$$P_{max} \geq P_{gen} \geq P_{min}$$

- Generators should not be dispatched with the generators’ reactive power MVAR at either limit.

$$Q_{gen} \neq Q_{max} \text{ and } Q_{gen} \neq Q_{min}$$

- Generators should have reasonable reactive power limits. When compared with maximum active power ( $P_{max}$ ), the power factor should be +0.8 (producing VARs) and -0.85 (consuming).
- Generator terminal bus voltages should be between 0.95 and 1.05 when the generator is regulating a non-terminal bus. This does not apply to wind farms and solar arrays.

### 3.4 Setup of IBR Generation

#### 3.4.1 Wind and Solar Generation

The energy supply for wind and solar generator plants varies with the time of day and the season. As such, the inverter-based resource (IBR) plant output must match the load scenario being simulated. For instance, when studying peak load during winter months, solar plant output may be less than its maximum, or zero, depending on the time of day the winter peak is expected to occur. Also, during summer peak months, extreme peak load conditions are usually the result of high heat and low wind. When setting up for an extreme summer peak scenario, wind generators should be set to zero.

#### 3.4.2 Battery Storage

Depending on the scenario being studied, battery storage units can act as either load or generation. As such, battery storage units should be set to mimic the behavior expected during the scenario being studied.


- Set as “Generation” when the scenario being simulated calls for no or low output from wind and/or solar generators. These may include winter peak (night), summer peak (no wind), or other potential interruptions to generation that require the use of battery storage.
- Set as “Load” when simulating light load conditions with an excess of generation in service. These may include wind generators during high wind periods, solar generators during mild spring conditions, steam generators with long startup times, and nuclear power plants.

#### 3.4.3 Power Factor for Non-synchronous Generation

FERC requires that all non-synchronous generators be designed to supply dynamic reactive power within the power factor range from 0.95 leading to 0.95 lagging while supplying continuous rated real power at the high side of the generator substation.<sup>5</sup> This is a minimum design requirement. It does not prevent a non-synchronous generator from operating outside this range. The full reactive power capability of the non-synchronous generator must be used to support voltage.<sup>6</sup> As such, non-synchronous generation shall provide a reactive capability curve that defines the reactive limits of the non-synchronous generator. Similar to reactive capability curves for a synchronous generator, the reactive capability curve for a non-synchronous generation plant will be constructed with the voltage at the POI held at 1.00 pu. Leading and lagging reactive capability at

<sup>5</sup> Required by FERC Order 827, Reactive Power Requirements for Non-Synchronous Generation, at paragraph 34.

<sup>6</sup> NERC Reliability Guideline, “BPS-Connected Inverter-Based Resource Performance,” Sept. 2018, p 25.

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different levels of real power output (100%, 90%...0% of rated MW) will be listed. The table generated will describe the reactive capability of the non-synchronous generator.

Non-synchronous generation includes wind generators, solar generators, and battery storage.

## 4.0 TRANSMISSION PLANNING: SYSTEM STABILITY CRITERIA

### 4.1 Introduction

Many variables affect the results of a stability study. These factors include, but are not limited to, the following:

- Pre-fault and post-fault system configurations.
- The system load level and load characteristics.
- Generation dispatch patterns, unit dynamic characteristics, and proximity to other generating unit types and locations of system disturbances.
- The type of generation dispatched (wind, solar, steam, gas turbine, battery).
- The type of load being served (residential, commercial, industrial, agricultural).
- Fault clearing time(s).
- The amount of flow interrupted as a result of switching out faulted elements.
- The 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.


### 4.2 General Criteria

Since 2005, PJM has become the TP for DEV-ET. 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-ET's specific stability practices in ET Planning Criteria. Such stability analyses include, but are not limited to, the following:

- A system impact stability study for BES<sup>7</sup> generation interconnection queue projects prior to the in-service date of the projects.
- A periodical baseline N-1-1 stability study for individual BES generation stations in compliance with the NERC Reliability Standard TPL-001.
- A periodical baseline N-1-1 stability study for the selected area using a dynamic load model for voltage stability purposes in compliance with the NERC Reliability Standard TPL-001.
- A periodical extreme events dynamic study for the selected area for voltage stability purposes in compliance with the NERC Reliability Standard TPL-001.
- An under-frequency load shedding (UFLS) study for selected areas periodically in compliance with the NERC Reliability Standard PRC-006 and SERC Reliability Standard PRC-006-SERC.

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<sup>7</sup> 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](https://www.nerc.com/pa/Stand/2018%20Bulk%20Electric%20System%20Definition%20Reference/BES_Reference_Doc_08_08_2018_Clean_for_Posting.pdf)

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- Studies to evaluate the capabilities of IBRs tied to the DEV-ET system. This includes low voltage ride through (LVRT), high voltage ride through (HVRT), primary frequency response,<sup>8</sup> and dynamic voltage response.<sup>9</sup>
- Other studies as needed to investigate and evaluate system disturbances.

The DEV-ET Planning team supports PJM in their stability analysis responsibilities and conducts internal stability analyses. Stability study activities performed by ET Planning include, but are not limited to, the following:

- 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 NERC Reliability Standard TPL-001.
- Delayed protective relay tripping system stability analysis per the requests from the DEV-ET System Protection Group.
- Stability studies required in PJM RTEP projects (including, but not limited to, projects involving FACTS devices). The substation’s physical security stability analyses are in compliance with NERC Reliability Standard CIP-014.
- Special stability studies required by long-term (above 5 years) strategic planning projects.

#### **4.3 Study Horizon**

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

- Enhancing system dynamic performance.
- Enhancing transmission protection.
- Enhancing generation protection.
- Enhancing generation equipment.
- Applying/modifying/removing RAS.
- Installing/modifying FACTS devices.
- Establishing operating restrictions for a contingency period covering forced or maintenance outages.


New transmission infrastructure may be required to ensure stability for the safe and reliable operation of the electric grid. In cases where a near-term stability study finds a potential problem and the plan to correct the problem requires a lead time beyond the near term, a stability study will be performed for a longer term to determine the impact.

Stability studies performed for the long-term horizon (more than 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-ET Transmission System on a longer time scale and prepare for challenges with the rapidly changing

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<sup>8</sup>FERC Order 842, Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response.

<sup>9</sup>FERC Order 827, Reactive Power Requirements for Non-Synchronous Generation.

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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-ET’s transmission expansion plan.

#### **4.4 Dynamic Data Collection**

PJM will collect dynamic data and submit it to the MMWG as outlined in the ERAG MMWG Procedural Manual.

DEV-ET Planning is responsible for submitting dynamic data to PJM for transmission owner (TO) equipment with dynamic characteristics (e.g., FACTS devices) and dynamic load data. The dynamic load data is collected from load-serving entities tied to DEV-ET.

#### **4.5 Stability Study Case Development**

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

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

- Changes to the model topology to include projects that will be completed before the targeted study date.
- Changes to area load levels and generator dispatch patterns to match the targeted study date and study scenario.
- Adjustments to dynamic model parameters to match assumptions described study scenario.
- When appropriate, meters will be added to measure the parameters (voltage, current, and frequency) necessary to confirm the performance of new or existing loads and generators.


After the dynamics model setup, the model is tested to ensure that the system is at a steady-state operating point. The test is performed by starting the simulation without any disturbance or changes. The simulation continues for 20–30 seconds. When done, the simulation plots are checked for oscillations. If all plots are flat (flat run) and no oscillations are found, the model is in a steady state. If the plots show oscillations, the initial conditions of the models must be edited.

#### **4.6 Selection of Generation Dispatch**

The economic dispatch used in internal power flow base cases may not represent conditions that 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 stability studies.

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

#### **4.7 Selection of Contingencies**

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

For a generation interconnection SIS or a TPL-001 compliance study, DEV-ET Planning uses the same contingency criteria and margins as PJM uses in its stability analysis.<sup>10</sup> For other stability analyses initiated by ET Planning, the most appropriate contingency criteria and margins are selected by ET Planning.

#### 4.8 What to Look for in Study Results

Checks are performed to make sure all online 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 in 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 pu 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 all oscillatory modes.
- **Acceptable generator voltage performance:** Generators are required to supply dynamic voltage support within the capability of the machine. For IBRs (non-synchronous machines), each generator must automatically respond to the need for voltage support, and each generator must be capable of supplying the maximum feasible reactive power while supplying maximum real power output. For synchronous machines, each generator must automatically respond to the need for voltage support and must be capable of supplying reactive power within a minimum power factor range of 0.95 leading to 0.90 lagging while supplying maximum real power output.<sup>11</sup>
- **Acceptable generator frequency response:** Generator models are required to provide primary frequency response with a maximum 5% droop and  $\pm 0.036$  Hz deadband. Each generator, including IBRs, must have real power controls with the ability to respond to frequency changes to halt a sudden rise or drop in frequency.<sup>12</sup>

If inter-area oscillations occur that have an unacceptable damping ratio and it is found that another entity's units are participating significantly in the oscillation, then a joint study between the affected parties is required.


To ensure transient stability is maintained with positive damping, N-1-1 contingencies are simulated with no re-dispatch after the first (N-1) contingency has occurred. If the oscillation damping is positive but does not reach the 3% limit, operational restrictions may be applied to ensure sufficient system damping.

For system conditions and contingencies that result in generator instability, additional analysis is performed to quantify the risk of a cascading event. 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.

<sup>10</sup> PJM Manual 14B: PJM Region Transmission Planning Process Attachment G: PJM Stability, Short Circuit and Special RTEP Practices and Procedures.

<sup>11</sup> PJM OATT VI, Part IX.B, GIA Appx 2 Section 4.6.1.1.1 New Facilities

<sup>12</sup> PJM OATT VI, Part IX.B, GIA Appx 2 Section 4.6.2.1 Governor or Equivalent Controls

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#### 4.9 Implementation Procedure

Stability analysis may warrant corrections or additional requirements to meet the criteria. The implementation procedure for such items depends on the type of corrections and the nature of the installation. The following is a general guideline for Transmission Planning to implement the plans needed to correct unacceptable system behavior.

##### 4.9.1 For Existing Installations

- System modifications that change fault-clearing times by making changes to existing relay set points shall be communicated to the DEV-ET System Protection group for implementation. PJM will be informed of the results of the analysis.
- A capital project shall be created to correct unacceptable system behavior related to transmission fault clearing times, which cannot be corrected by changing the relay set points. Capital projects shall first be validated, approved, and assigned cost and construction responsibility by the PJM RTEP process.
- Output restrictions and/or unit trip(s) for the next pending contingency condition identified by DEV-ET 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 from 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.

##### 4.9.2 For All 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 the PJM Queue. For the transmission-related requirements, DEV-ET shall communicate these to the Substation Engineering group for design and implementation.

##### 4.9.3 New IBRs and Loads Dominated by Electronics

Wind turbine power plants, PV power plants, battery storage units, and data centers are inverter-based equipment that are dominated by the behavior and controls of inverter-based systems. Inverter-based equipment introduces system responses not normally encountered with rotating machines (generators and motors). Consequently, electromagnetic transient (EMT) simulations are performed to determine the system response to a fault when inverter-based equipment is present. IEEE Std 2800-2022<sup>13</sup> provides guidance on the EMT data requirements for IBRs connected to the Transmission System and should be followed. Due to the unique design of the equipment, the equipment manufacturer is the best source of EMT models. Therefore, EMT models for generators and loads that are dominated by inverters should be supplied by the equipment manufacturer(s).

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<sup>13</sup> IEEE Std 2800-2022, “IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems,” Annex G.

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## 5.0 NUCLEAR PLANT INTERFACE COORDINATION

### 5.1 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 achieve the highest level of safety.

### 5.2 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 the 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 ensure 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 as “GDC-17.”

### 5.3 Design Requirements

PJM and DEV-ET will design the system to meet the GDC-17 requirements. In order to provide adequate voltage to safety systems, the Nuclear group periodically provides NPIR to DEV-ET. Dominion Energy Transmission

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Planners should consult the latest version of applicable Interface Agreements between DEV-ET 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 LTCs should be locked post-contingency.

For violations of the NPIRs, the transmission planner will contact the GDC-17 coordinator for Electric Transmission Planning. PJM/DEV-ET Planning will notify DEV-NUC 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, DEV-NUC will determine if any further action is required and respond to DEV-ET Planning. DEV-ET Planning will work with PJM to resolve concerns identified by DEV-NUC.

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

#### **5.4 Underfrequency Studies**

The UFLS program 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 RCP is set to trip at 58.05 Hz with a time delay of 100 milliseconds.

#### **5.5 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.

#### **5.6 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 that 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 Reliability Standard NUC-001-2 (or its successor), the GDC-17 coordinator shall retain evidence of communications with the appropriate nuclear contacts.


#### **5.7 Changes to the System**

NERC Reliability Standard NUC-001-2, R8 states the following:

“...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.”

### **6.0 REFERENCES**

1. NERC Reliability Standard TPL-001, Transmission System Planning Performance Requirements
2. NERC Reliability Standard PRC-012, Remedial Action Schemes
3. NERC Reliability Standard PRC-017, Remedial Action Scheme Maintenance and Testing
4. NERC Technical Reference Document, Dynamic Load Modeling, December 2016
5. NERC Reliability Guideline, Reactive Power Planning, December 2016


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6. NERC Reliability Guideline, Electromagnetic Transient Modeling for BPS Connected Inverter-Based Resources—Recommended Model Requirements and Verification Practices, March 2023
7. NERC Libraries of Standardized Powerflow Parameters and Standardized Dynamics Models, Version 1, October 15, 2015
8. NERC 2012 Special Assessment Interconnection Requirements for Variable Generation, September 2012
9. NERC Reliability Standard NUC-001
10. IEEE Std 1110, IEEE Guide for Synchronous Generator Modeling Practices and Parameter Verification with Applications in Power System Stability Analyses
11. IEEE Std 2800, IEEE Standard for Interconnection and Interoperability of Inverter-based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems
12. IEEE Std 519, IEEE Standard for Harmonic Control in Electric Power Systems
13. Transmission System Performance SERC Supplement
14. Nuclear Switchyard Interface Agreement CO-AGREE-000-IA1
15. Nuclear Switchyard Interface Agreement System Analysis Protocol CO-AGREE-000-IA1-4
16. PJM Manual 39—Nuclear Plant Interface Coordination
17. PJM Manual 14B—PJM Region Transmission Planning Process

## 7.0 REVISION HISTORY

**Table 4. Revision History**

<b>Revision Date</b>	<b>Revision #</b>	<b>Description</b>	<b>Revised By</b>	<b>Effective Date</b>
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

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Revision Date	Revision #	Description	Revised By	Effective Date
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
01/01/2024	22.0	Revision as a part of Facilities Interconnection Requirements	ET Planning Staff	01/01/2024
08/01/2024	23.0	See Details for Revision 23.0 below	Kristen Custer	09/01/2024
03/11/2025	24.0	See Details for Revision 24.0 below	Kristen Custer	04/01/2025
09/10/2025	25.0	See Details for Revision 25.0 below	Kristen Custer	10/01/2025
03/01/2026	26.0	See Details for Revision 26.0 below	Thomas Mconnell and Danovo Energy Solutions	04/01/2026

\*For these revisions, the planning guideline was an attachment within the DEV Facilities interconnection 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 the 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 of all sections.

#### **Details for Revision 5.0**

- Revised the following:
  - Section 2.12: Clarified content regarding synchronizing of Facilities.

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- Exhibit A: Changed loading criteria to not exceed the emergency rating of the 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 the 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 3.2.10—End-of-life Criteria.
- Reformatted headers to improve PDF navigation via bookmarks.

#### **Details for Revision 10.0**

- Clarifications and annual review.
- Reformatted the approval area and moved to the title page.
- Reformatted Revision History and moved to the end of the document (s).
- Modified throughout to reflect NERC Reliability Standard TPL-001-4, including the replacement of Table 1 and Table 2 and deletion of “Category D Multiple Testing Requirements” (previously Section C.2.7 in Revision 9.0 document).
- Section 3.2.6—Radial Transmission Lines: Expanded to introduce new criteria and metrics.
- Section 3.2.7—Critical Transmission Lines: Inserted new section.
- Section 4.5—Stability Study Case Development: Clarified that PJM (not DEV-ET) performs simulations to cover all generating plants over a three-year study cycle (not five-year).
- Former Section G: Modified electrical arrangements and clarified lines of demarcation.

#### **Details for Revision 11.0**

- Section 3.0—Planning Principles and Standards, Table 1 Notes: Added Note “C”
- Section 3.0—Planning Principles and Standards, Table 2 Notes: Added Note “G” and re-numbered other notes to differentiate from Table 1 (Note G became Note I in v15)
- Section 4.6—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).
- Table 1 and Table 2: Removed references to DC line (does not apply to Dominion).

- Table 1’s Note B and Table 2’s Note F: Clarified “may not be required if the loss of consequential and non-consequential load up to 300 MW achieves a return to the STE rating.”
- Section 5.3—Design Requirements: 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 5.0 and 6.0.
- Acronyms : Added definition of “Good Utility Practice.”

**Details for Revision 13.0**

- Revised references for the new Dominion Energy corporate identity.
- Section 3.0—Planning Principles and Standards: Added Table 3 Steady-State Performance Extreme Events and Dominion Energy Criteria and associated notes and refined notes for Table 1 and Table 2.
- Added Section 3.2.9 Substation: Limitation on Direct-connect Loads.

**Details for Revision 14.0**

- Clarified that some notes to Table 1, Table 2, and Table 3 are “Dominion Energy” notes.
- Edited Dominion Energy Note “B” for Table 1 and Note “F” for Table 2 to remove the phrase “and non-consequential” [load]. (Note F became Note H in v15.)
- Edited Dominion Energy Note “C” for Table 1 and Note “G” for Table 2 to refer to the new Section 3.2.1.3. (Note G became Note I in v15.)
- Added Section 3.2.1.3—Critical Stress Case Development and Studies

**Details for Revision 15.0**

- Reviewed to ensure alignment with Facility Interconnection Requirements, v15, effective 01/01/2019.
- Table 1, Table 2, and Table 3: Added new notes to Table 1 and Table 2, requiring re-labeling of notes in Table 1, Table 2, and Table 3 as follows:


**Table 5. Revision 15.0**

Previously	Now	Previously	Now	Previously	Now
A	<b>A</b>	E	<b>G</b>	J	<b>M</b>
B	<b>B (Edited)</b>	F	<b>H</b>	K	<b>N</b>
-	<b>C (New)</b>	G	<b>I</b>	L	<b>O</b>
C	<b>D</b>	-	<b>J (New)</b>	M	<b>P</b>
-	<b>E (New)</b>	H	<b>K</b>	N	<b>Q</b>
D	<b>F</b>	I	<b>L</b>		

Section 3.0—Planning Principles and Standards: Simplified reference to Nuclear generation re-dispatch.

- Section 3.2.10—End-of-life Criteria: Edited discussion and list of factors considered.
- Section 3.3—Generation Dispatch Used in DEV-ET Power Flow Studies: New section.
- Section 5.0—Nuclear Plant Interface Coordination:
  - 5.3—Design Requirements: Removed tables of NPIR voltage limits, voltage drops, and contingency scenarios.
  - 5.7—Changes to the System: Simplified content to contain only the NUC-001-2, R8 quotation.

**Details for Revision 16.0**

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- Table 1, Note B: Deleted specific reference to 230 kV (table applies to several voltages).
- Table 2, Notes F and G: Removed specific references to 500 kV (500 kV is inherent to this table).

#### **Details for Revision 17.0**

- Updated dates, names, and revision numbers.
- Table 1 and Table 2: Added contingency for Category P4, Event 6
- Section 3.0—Planning Principles and Standards: Added language describing N-1-1 contingency analysis.
- Section 3.2.6—Radial Transmission Lines: Edited discussion.
- Section 3.2.10—End-of-life Criteria: Removed evaluation of lines operating below 500 kV and edited assessment language.
- Section 4.0—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 6.0—References: Updated to include reference to PRC Standards 12 -17.

#### **Details for Revision 18.0**

- Table 1: Decreased the high voltage limits for 138kV lines.
- Table 2: Revised the high voltage limits for 500kV and above lines.
- Table 3: Revised Note “Q” Extra High Voltage (EHV) limit to 109.6%.

#### **Details for Revision 19.0**

- Updated Signature Page.
- Section 3.0—Planning Principles and Standards: Revised time frame of system adjustments.
- Table 1: Removed the Note “A,” “B,” and “C” and set the Thermal Limits to 100% of Short Term Emergency (STE). Note C was added for system adjustments at the initial condition in P3 and P6. In addition, system reinforcements for load loss of more than 300 MW are indicated.
- Table 2: Removed the Note “F,” “G,” and “H” and set the Thermal Limits to 100% STE. Note that F was added for system adjustments at the initial condition in P3 and P6. In addition, system reinforcements for load loss of more than 300 MW are indicated.
- Table 3: Changed the Note References.
- Section 3.2.2—Power Transfers: Added footnote for DEV-ET criteria on Generation Deliverability.


#### **Details for Revision 20.0**

- Updated Signature Page.

#### **Details for Revision 21.0**

- Updated Signature Page.
- Fixed minor typos and grammatical edits throughout the entire document.
- Section 3.0—Planning Principles and Standards: For Table 1 and Table 2, P5 updated to include future reference to TPL-001-5.1 (Effective date is 07/01/2023).
- Section 3.0—Planning Principles and Standards: Note 13 is updated to include future reference to TPL-001-5.1 (Effective date is 07/01/2023).
- Section 3.2.6—Radial Transmission Lines: Criteria modified to address a wider range of situations.

#### **Details for Revision 22.0**

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- Updated Signature Page.
- Revision as a part of Facilities Interconnection Requirements (FIR).

#### **Details for Revision 23.0**


- Revision contributors include Aaron Winter, Amirreza Sahami, Andrea Pinceti, Colleen Wallace, Harrison Potter, Katelynn Vance, Keith Graham, Mark Gill, Mohsen Mahoor, Nedim Besirevic, Peter Nedwick, Praveen Dhanasekar, YaJun Zheng, and Quanta Technology.
- Removed signature page and consolidated on FIR cover page.
- Added language and a link to NERC standards in Section 2.1—NERC Transmission Planning Standards and Documents.
- Language and style edits to make it more readable.
- Added Section 2.4—IEEE Industry Standards to explain the use of IEEE standards.
- In Section 3.0—Planning Principles and Standards, the definition of CAP was expanded to “Corrective Action Plan” and added a footnote to the NERC glossary of terms.
  - e. In Section d—
- Voltage Limits at Generating Stations, PV arrays were added, with the exception of wind turbines.
- The language in Section 3.2.3—Equipment Ratings was changed to match industry usage.
- Added bullet point in Section 3.3—Generation Dispatch Used in DEV-ET Power Flow Studies to include generation, which is dependent on the weather.
- Added language and list items 1–4 to Section 3.3—Generation Dispatch Used in DEV-ET Power Flow Studies to align the DEV power flow case setup with the NERC power flow case quality metrics.
- Added Section 3.4—Setup of IBR Generation to account for IBR generation during a power flow case setup.
- Added Section 3.4.2—Battery Storage to account for battery storage during a power flow case setup.
- Added Section 3.4.3—Power Factor for Non-synchronous Generation with footnotes to account for non-synchronous generator pf settings.
- Added bullets to Section 4.1—Introduction to account for the type of generation and type of load.
- Added bullet to Section 4.2—General Criteria with language to require evaluation of voltage and frequency response.
- Added bullet to Section 4.3—Study Horizon to include system dynamic performance.
- Added language to Section 4.5—Stability Study Case Development to include a flat start of a model.
- Added bullets to 4.8—What to Look for in Study Results to help identify generator voltage performance and frequency performance.

#### **Added Section 4.9.3—**

- New IBRs and Loads Dominated by Electronics to account for generation and load that used inverters.
- Fixed naming convention in the reference section and added references.

#### **Details for Revision 24.0**

- Revision contributors include the following: Mohsen Mahoor, Daniel Ridenour, Andrea Pinceti, Candace Marshall, Jonathan Deverick, Ibukunoluwa Korede, Katelynn Vance, Kristen Custer, Keith Graham, and Quanta Technology.
- Document formatting (fonts, margins, etc.) updated to improve readability. Changed the main font from Arial to Aptos.
- Updated abbreviations and acronyms.

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- Acronyms moved to the front of the document to align with the main FIR document.
- Resized all figures and improved quality.
- Renumbered figures to match formatting.
- Grammatical modifications including capitalization, spelling, punctuation, and consistency.
- Modified the numbering of sections and chapters from alphabetical order to numerical.
- Added Section 2.5 to describe the coordinated study process.
- Added clarifying language around N-1-1 contingency analysis procedures and interpretations.
- Voltage drop criteria added to Table 2 and Table 3.
- Updated NERC category P4 in Table 3 to reflect changes in two columns corresponding to P4.6 contingency category.
- Clarified language in Section 3.1.7 to reflect the number of direct-connect loads to be limited to the number that can be accommodated.
- Added language to Section 4.5 to reflect the appropriate use of meters.
- Clarified language in Section 4.8 to remove inter-area oscillations and limit damping to 3%.
- Removed references to IEEE Std 1547.

#### **Details for Revision 25.0**

- Revision contributors include the following: Nancy Ashberry, Daniel Ridenour, Chris Dunn, Kristen Custer, Keith Graham, and Quanta Technology.
- General editorial updates: grammar, punctuation, capitalization, consistency.
- Formatting changes: section numbering made fully numeric; figures resized/renumbered; tables cleaned for readability.
- Critical Transmission Line definition reaffirmed.  
Tapped load limits restated
- End-of-life criteria strengthened with explicit reliability and replacement triggers.

#### **Details for Revision 26.0**


- New content added to Section 4.6.

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# Attachment 2

## Customer Delivery Point Requests

### Dominion Energy Virginia—Electric Transmission Facility Interconnection Requirements

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## ABBREVIATIONS AND ACRONYMS

Term	Definition
AHU	Air-handling Unit
AOI	Acknowledgment of Intent
BESS	Battery Energy Storage System
CMLD	Composite Load Model
CRAC	Computer Room Air Conditioner
CRAH	Computer Room Air Handler
DEV	Dominion Energy Virginia
DEV-ET	Dominion Energy Virginia—Electric Transmission
DPE	Delivery Point Exchange
DPR	Delivery Point Request
ECM	Electronically Commutated Motors
EDC	Electric Distribution Company
EG	Emergency Generator
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FIR	Facility Interconnection Requirements
MOA	Mutual operating agreement
NEMA	National Electrical Manufacturers Association
NERC	North American Electric Reliability Corporation
UPS	Uninterruptible Power Supply

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## 1.0 CUSTOMER DELIVERY POINT REQUESTS IMPACTING DOMINION ENERGY VIRGINIA FACILITIES

Electric Distribution Companies (EDC) (herein referred to as “Customers”) shall initiate all requests that impact a Dominion Energy Virginia—Electric Transmission (DEV-ET) Facility by electronically submitting the required information through the online Dominion Energy Virginia (DEV) Delivery Point Exchange (DPE) application. Should this web-based request site be unavailable, please contact your customer account point of contact for assistance. Delivery point requests (DPRs) shall be submitted for any of the following:


- Request to install, modify, or remove DEV-ET Facilities.
- Request to install, modify, or increase load served at a DEV-ET delivery point.
- Discontinue the delivery of electricity to a DEV-ET delivery point.

Additionally, Customers shall submit a DPR when making any changes to the Customer’s Facilities that are reasonably anticipated to impact the operation of or lead to a modification to DEV-ET Facilities. This includes, but is not limited to, new or modified distribution or generation equipment.

Customer DPRs should be submitted as soon as the minimum required information is available. As the project matures and additional or updated information becomes available, it is the Customer’s responsibility to submit a revision to the original request with the new information. Each request revision will supersede information from any previous revision.

### 1.1 Customer Request Instructions

1. Customers shall submit a complete DPR through the DPE, ensuring accurate and complete information is provided in accordance with the requirements laid out in this document and subsequent fields in the DPE.
2. The DPE will be used for communications between DEV-ET and the Customer throughout the process described in Section 1.2. Customers should enable notifications to continuously monitor their DPRs.
3. For DPRs in support of data centers, after performing a review of the DPR against the mutual operating agreement (MOA) between DEV and the Customer, DEV-ET will place the DPR into a queue consisting of batches organized by the request submittal date. The queue process is further described in Section 1.2.1.
4. At any stage in the process, when modifications are necessary to a DPR due to new or changing information from the Customer and/or developer, a revised DPR must be submitted following the same process as a new DPR in the DPE. Upon receipt, DEV-ET will conduct its normal evaluation process, which will include a review of the revised submittal against scope change limits. If scope change limits are deemed to be exceeded, a formal letter will be provided to inform the Customer of the issue and the resulting action.
5. If no information is appropriate for a particular field, enter “N/A.”
6. Noteworthy Load Characteristics and Customer equipment information must be submitted at least 90 days prior to the target energization date determined during DEV-ET’s review of project feasibility.
7. Customers are encouraged to provide peak demand data (kW/kVAR) at the most granular level available for each year, including Summer and Winter peak demands. Monthly data may be specifically requested for the first 1 to 3 years of operation.
8. Customers are expected to make their best effort to understand DEV-ET’s protection philosophies and design their protection systems accordingly. Customers should review the NERC Incident Review on Large Load Loss and ensure their design decisions do not create unintended consequences for the DEV-ET system. Any questions and clarifications should be directed to the Customer account point of contact.

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## 1.2 Delivery Point Request Process

All DPRs will advance through a process in which Customer information will be required at each stage so that DEV-ET can maintain its strategy to plan, design, construct, and operate the delivery point. Each step in the process will require the Customer to provide information before proceeding to the next stage. The type of information may depend on the type of DPR (see stage-specific sections to follow).

### 1.2.1 Initiation

The Customer submits a complete request that contains all required information and attachments. The request is reviewed by DEV-ET to ensure all required information is present and acceptable according to the MOA between DEV-ET and the Customer.

If the DPR is for a data center, DEV-ET will place the DPR into a queue consisting of batches organized by the request submittal date. This initial batch assignment will be communicated to the requesting party through the DPE. For data center DPRs, DEV-ET will then perform an initial review of the DPR to confirm that sufficient land, constructible interconnection routes, and acceptable environmental conditions exist. DEV-ET will review and update batch assignments annually, with these updates also communicated through the DPE. When a DPR has progressed through the queue and is ready to advance to Feasibility, the requesting party will be required to submit an AOI revision to the DPR within 45 days of receiving the communication through the DPE. The AOI revision will require the Customer to advance through the DPR and update any information that has changed or provide any new information required in the DPR in accordance with the most current revision of the Facilities Interconnection Requirements (FIR). Upon completing the AOI revision to the DPR, the final signature on the DPR signifies that the DPR is accurate and complete at the time of signature and that all required information has been provided. The AOI revision to the DPR will be reviewed by DEV-ET.

For non-data center DPRs, the DPR will bypass batching, the initial review, the queue, and AOI requirements.

### 1.2.2 Feasibility

The current/confirmed DPR, along with the additional information required in this stage, is used to conduct a full feasibility analysis of the DPR to determine the realistic energization date of the project. Once the feasibility analysis has been completed and the delivery point is deemed feasible, a Letter Agreement with a target date will be issued and signed by all parties, and the delivery point can proceed to Development.

### 1.2.3 Development

The project proceeds through conceptual and detailed engineering, and any necessary regulatory reviews, to finalize the design and prepare for construction.

### 1.2.4 Execution


The project is constructed and energized.

## 2.0 INITIATION SUBMITTAL

### 2.1 Customer Information

Table 1. Customer Submittal Information


Item	Information
Request Date	
Requestor Company Name	
Requestor Company Address	
Name of Contact Person	
Contact Mobile Number	
Alternate Phone Number	
Contact Email	
Contact Fax Number	

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## 2.2 Request Type

Table 2. Request Type

Item	Information
Name of Delivery Point	
Description of Request	
Reason for Request	
Is this Delivery Point Request being submitted to support a Data Center Project?	
Will this requested Delivery Point have a load of greater than 100 MW?	
Is this a request for revision to an active Delivery Point Request?	
Is this Delivery Point Request related to any other active delivery point request(s) with a project in progress? If so, list related delivery points.	
Is this Delivery Point Request a part of a campus or planned group of related delivery points? If so, what is the name of the campus?	
How many delivery points are on the campus?	
Where is this Delivery Point Request in the order of planned energization dates for the delivery point campus?	
What is the expected total load of the campus or planned group of related delivery points?	
Please provide any available development information, such as campus timeline, site layout, load ramp, etc., for the campus or planned group of related delivery points.	
Delivery Point Location (Coordinates in Decimal Degrees)	
Description of Delivery Point Facilities Route	
Is a new line extension involved?	

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### 2.3 New Delivery Point Information

**Table 3. New Delivery Point Information**

Item	Information
New Delivery Point Voltage (kV)	
New Peak kVA Capacity of Delivery Point Facilities	
New Peak kVA Demand of Delivery Point Facilities	

### 2.4 Present Delivery Point Information

**Table 4. Present Delivery Point Information**

Item	Information
Present Delivery Point Voltage (kV)	
Present Summer Peak kW Demand	
Present Summer Peak kVAR Demand	
Present Winter Peak kW Demand	
Present Winter Peak kVAR Demand	
Present Maximum kVA Capacity of Delivery Point Facilities	
Present Maximum kVA Demand of Delivery Point Facilities	

### 2.5 Customer Timing

**Table 5. Customer Timing**


Item	Information
Requested Date to Energize	
Expected Date Customer’s Construction to Commence	
Expected Completion Date of Customer Work	
Date Requested for Dominion Construction to Commence	
Requested Completion Date of Dominion Energy Work (De-energized)	
Other Milestones	

**2.6 Anticipated Peak Seasonal Demand**

Provide anticipated peak seasonal demand (kW/kVAR) for the years and seasons below.

**Table 6. Anticipated Peak Seasonal Demand**

Year	Calendar Year	Summer Peak Demand (kW)	Summer Peak Demand (kVAR)	Winter Peak Demand (kW)	Winter Peak Demand (kVAR)
Year 1					
Year 2					
Year 3					
Year 4					
Year 5					
Year 6					
Year 7					
Year 8					
Year 9					
Highest peak in first 10 years					
Year 15					

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**2.7 Required Attachments (All Delivery Point Requests)**

- 1. Preliminary One-Line Diagram:** A practical initial version of an electrical engineering diagram that shows how the requesting party anticipates the power flow from the delivery point to the load, along with critical transmission connections to Customer equipment, protection components, and equipment ratings.
- 2. Preliminary Site Plan\*:** A scaled and dimensioned plan view of the delivery point(s) and development (including campus if applicable) that displays the area of the substation pad and access road plans to confirm adequate space is available for the transmission elements of a delivery point.

\*Note: Submission of the Preliminary Site Plan is used to infer that the developer of the property has a path to, or proof of, site control, with evidence that the property includes space for the transmission elements of a delivery point.


**2.8 Required Actions (For Data Center Delivery Points Only)**

- 1. Acknowledgement of Intent (AOI):** When a DPR has progressed through the queue and is ready to advance to Feasibility, the requesting party will be required to submit an AOI revision to the DPR within 45 days of receiving the communication through the DPE. The AOI revision will require the Customer to advance through the DPR and update any information that has changed or provide any new information required in the DPR in accordance with the most current revision of the FIR. Upon completing the AOI revision to the DPR, the final signature on the DPR signifies that the DPR is accurate and complete at the time of signature and that all required information has been provided. The AOI revision to the DPR will be reviewed by DEV-ET.

**2.9 Requirement of Authorization**

The signature below authorizes Dominion Energy to proceed with the planning, design, engineering, and estimation of the Project cost as appropriate for Dominion Energy 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:	Authorization Date:
_____	_____
Printed Name:	Phone:
_____	_____
Title:	Email:
_____	_____

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### 3.0 FEASIBILITY SUBMITTAL

#### 3.1 Required Attachments (For Data Center Delivery Points Only)

1. **30% Site Plan\***: A site plan package detailing the delivery point(s) and development (including campus if applicable) that includes at a minimum:

- Entire substation pad area contained on one sheet and noted as “Electric Substation”
- Existing contours with elevations in feet
- Proposed contours with elevations in feet
- Substation fence line with dimensions
- Northings and Eastings at each corner of fence
- Entrance roads with roadway width (20’ min) and radii (55’ min)
- Proposed transmission line corridors
- Approximate location and size of proposed stormwater management facilities

DEV-ET will review and comment on the site plan to accommodate substation grading requirements.

2. **Zoning Conformance Letter\***: A letter from the locality (County, City, etc.) stating the appropriate agency (planning and zoning, public works, etc.) is aware that this is a data center development that includes a Dominion Energy substation, and that the parcel is (or will be) zoned appropriately, or the site plan will go through the appropriate use permitting process for a data center development with a Dominion Energy substation.

\*Note: Submission of the 30% Site Plan and Zoning Conformance Letter is used to infer that the Customer has a path to, or proof of, site control.


#### 3.2 Required Actions (All Delivery Point Requests)

1. **Letter Agreement (LA)**: A signed agreement between Dominion Energy Virginia and an Electric Distribution Company governing the work to be performed to support a DPR. Dominion Energy’s Wholesale Contracts group will generate this agreement based on the DPR data and parameters, as provided by the Customer, as well as input from Dominion Energy stakeholders. Both parties’ execution of a Letter Agreement is required for the DPR to progress to the Development stage.

### 4.0 DEVELOPMENT SUBMITTAL

#### 4.1 Required Attachments (For Data Center Delivery Points Only)


1. **100% Grading Plan^**: Final designed grading plan showing the fully graded condition of the site, including all to-be-constructed finished elevations, slopes, drainage features, cut/fill limits, and site access.
2. **Federal Permits^**: Any and all permits that may be required from US Federal agencies including, but not limited to, Federal Energy Regulatory Commission (FERC), Environmental Protection Agency (EPA), and others, to successfully execute the work associated with the DPR.
3. **State Permits^**: Any and all permits that may be required from state agencies to successfully execute the work associated with the DPR.
4. **Local Permits^**: Any and all permits that may be required from local agencies to successfully execute the work associated with the DPR.

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^Note: Submission of the 100% Grading Plan and Federal, State, and Local Permits is used to infer that the Customer has proof of site control.

**4.2 Required Attachments (All Delivery Point Requests)**

- 1. Construction One-Line Diagram:** An electrical engineering diagram that shows how the requesting party plans to construct the power flow from the delivery point to the load, along with critical connections, protection components, and equipment ratings.

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## 5.0 EXECUTION SUBMITTAL

### 5.1 Noteworthy Load Characteristics (Submitted at Least 90 Days Prior to Target Energization Date)

#### 5.1.1 Load Composition

**Table 7. Load Composition**

Item	Description	Percentage
<b>Motor A</b>	<p>Percentage of load consisting of three-phase induction motors with low inertia (<math>H = 0.10</math> sec) driving constant torque loads. These motors are found in commercial/industrial air conditioning compressors and refrigeration systems (not NEMA B).</p> <p>Smaller 5–15 HP compressor motors are typical of rooftop air conditioning units commonly found at grocery stores, consumer products stores, and malls.</p> <p>Larger 200–500 HP compressor motors are typical of large commercial buildings' central cooling systems.</p>	%
<b>Motor B</b>	<p>Percentage of load consisting of three-phase induction motors with high inertia (<math>H = 0.25</math>–<math>0.10</math> sec) driving loads whose torque is proportional to speed squared. These motors are found in commercial ventilation fans and air-handling systems.</p> <p>5–25 HP fan motors, which are normally NEMA B motors.</p>	%
<b>Motor C</b>	<p>Percentage of load consisting of three-phase induction motors with low inertia (<math>H = 0.10</math>–<math>0.20</math> sec). This represents motors commonly found in commercial water circulation pumps in central cooling systems.</p> <p>5–25 HP pump motors, which are usually NEMA B motors.</p>	%
<b>Motor D</b>	<p>Percentage of load consisting of single-phase air conditioners. This represents commonly found residential single-phase air conditioners.</p>	%
<b>Electronic Load</b>	<p>Percentage of load consisting of power electronic converters. These are constantly active and reactive power loads that include the following: consumer electronics (plasma and LED televisions, cell phones and tablets, clocks, radios, etc.), appliances (high-efficiency appliances such as refrigerators, washing machines, etc.), and office equipment (printers, copy machines, servers, etc.).</p>	%
<b>Static Load</b>	<p>Percentage of load that will be static. This represents electric ovens, water heaters, incandescent lighting, and all other loads whose behavior changes with voltage magnitude.</p>	%
<b>Total Load Percentage</b>		<b>100%</b>

\* The listed load characteristics are parameters needed to perform simulations using the composite load model referenced in “NERC Technical Reference Document for Dynamics Load Modeling, December 2016.”

### 5.1.2 Composite Load Model

**Table 8. Composite Load Model**

Item	Information
Total Installed Load (kW)	
Total Installed Distributed Generation (kW)	
Total Installed Low-side Capacitor Bank Demand (kVAR)	
Total Synchronous Motor Load (kW)	
Motor Start Type	
Motor Speed Control Method	

### 5.1.3 Data Center Load Information

**Table 9. Data Center Load Information**

Item	Information
Total Rated Load, Including IT, Power Distribution, and Cooling (kW)	
Overall Data Center Power Factor (Lead/Lag)	

### 5.1.4 Data Center Load Percentages

**Table 10. Data Center Load Percentages**

Item	Summer Daytime	Summer Nighttime	Winter Daytime	Winter Nighttime
Computing/Server Load				
Lighting Load				
Power Distribution Losses				
Cooling/Heating Load				

### 5.1.5 Data Center Cooling System

Table 11. Data Center Cooling System

Category	Item	Information
<b>Forced Cooling System</b>	Computer Room Air Conditioners (CRAC) with Internal Compressors	<input type="checkbox"/>
	Computer Room Air Handlers (CRAH) Are Supplied with Chilled Water	<input type="checkbox"/>
	Air-handling Units (AHU) Dedicated to the Data Center Space	<input type="checkbox"/>
	Other	<input type="checkbox"/>
<b>Cooling System Motor-driven Components</b>	Single-speed Motors That Are Operated across the Line (Motors Connected Directly to the AC Supply)	<input type="checkbox"/>
	Motors Controlled by Variable/Adjustable Speed Drives or Electronically Commutated Motors (ECM)	<input type="checkbox"/>
	Other	<input type="checkbox"/>

### 5.1.6 Data Center Voltage Performance

Table 12. Data Center Voltage Performance

Item	Voltage	Milliseconds (ms)
<b>Voltage Base (kV)- specify for per-unit calculations</b>		
<b>Voltage sag level/duration at which the computer/server load disconnects from the utility system (these may transfer to a local UPS)</b>	p.u.	msec
<b>Voltage sag level/duration at which the cooling load disconnects from the system (these may transfer to an emergency generator or local power source)</b>	p.u.	msec
<b>How are voltage sag levels measured for the disconnect action?</b>	<input type="checkbox"/> Per phase	
	<input type="checkbox"/> Three-phase RMS	
<b>Voltage swell level/duration at which the computer/server load disconnects from the utility system (these may transfer to a local UPS)</b>	p.u.	msec
<b>Voltage swell level/duration at which the cooling load disconnects from the system (these may transfer to an emergency generator or local power source)</b>	p.u.	msec
<b>How are the voltage swells measured for the disconnection action?</b>	<input type="checkbox"/> Per phase	
	<input type="checkbox"/> Three-phase RMS	

### 5.1.7 Data Center Frequency Performance

Table 13. Data Center Frequency Performance

Item	Hertz
The lowest frequency at which the data center will disconnect from the system	Hz
The highest frequency at which the data center will disconnect from the system	Hz

### 5.1.8 Data Center Reconnection Method after Automatic Disconnect from Service Provider System

Table 14. Data Center Reconnection Method after Automatic Disconnect from Service Provider System

Category	Type	Information			
<b>Manual</b>	Manual	<input type="checkbox"/>	Yes		
		<input type="checkbox"/>	No		
<b>Immediate Reconnect</b>	Immediate Reconnect ( <i>No Deliberate Time Delay</i> )	<input type="checkbox"/>	Yes	If YES, complete the information below in this Immediate Reconnect section	
		<input type="checkbox"/>	No		
	Voltage Base (kV)-specify for per-unit calculations				
	$V_{high}$ : Reconnect when voltage is below		p.u.	deadband	msec
	$V_{low}$ : Reconnect when voltage is above		p.u.	deadband	msec
	$f_{high}$ : Reconnect when frequency below		Hz	deadband	msec
	$f_{low}$ : Reconnect when frequency above		Hz	deadband	msec
<b>Delayed Reconnection</b>	Delayed Reconnection	<input type="checkbox"/>	Yes	If YES, complete the information below in this Delayed Reconnection section	
		<input type="checkbox"/>	No		
	Time delay after voltage is within acceptable limits to reconnect		sec		
	Voltage Base (kV)-specify for per-unit calculations				
	$V_{high}$ : Reconnect when voltage is below		p.u.	deadband	msec
	$V_{low}$ : Reconnect when voltage is above		p.u.	deadband	msec
	Time delay after frequency is within		sec		

Category	Type	Information		
	acceptable limits to reconnect			
	$f_{high}$ : Reconnect when frequency below	Hz	deadband	msec
	$f_{low}$ : Reconnect when frequency above	Hz	deadband	msec

### 5.1.9 Reconnect Loading Process


Table 15. Reconnect Loading Process

Item	Information	
Are all loads reconnected at once?	<input type="checkbox"/>	Yes
	<input type="checkbox"/>	No
Continuous ramp rate for ramping to reconnect		kW/sec
Number of steps for stepwise ramping to reconnect		Step(s)
Load increase per step for stepwise ramping to reconnect		kW/step

### 5.1.10 Data Center Emergency Backup Power System Details

Table 16. Data Center Emergency Backup Power System Details

Item	Information	
Emergency generator (EG) capacity		kW
Duration of EG based on available fuel		hours
Battery energy storage system (BESS) discharging capacity		kW
Duration of BESS discharge based on fully charged battery capacity		hours
Percent of Data Center Load which can be carried by EG and/or BESS		%
Can the Data Center Backup Power System participate in demand-side management in a grid emergency or as an ancillary service?	<input type="checkbox"/>	Yes
	<input type="checkbox"/>	No
In the event of a planned or unplanned disconnection from the grid, can the Data Center be Islanded and operate with the EG and/or BESS?	<input type="checkbox"/>	Yes
	<input type="checkbox"/>	No
What percent of the server farm load could be redistributed to redundant server sites across the world?		%
If the data center trips offline, what percent of the load will be transferred to other server farms?		%
How fast can load transfers be completed?		sec

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## 5.2 Customer Equipment

Customer Equipment information must be submitted at least 90 days prior to the energization date determined during Dominion Energy’s review of project feasibility.

**Table 17. Customer Equipment**


Item	Information
Transformer Primary Voltage (kV)	
Transformer Secondary Voltage (kV)	
Transformer Nameplate Capacity (MVA)	
Transformer Temperature Rise (°C)	
Connection (e.g., Wye-Wye)	
Transformer Taps	
Transformer Impedance (%)	
Isolation Device Type and Rating	
Protection Device Type and Rating	

## 5.3 Required Attachments (For Data Center Delivery Points Only)

- As-Built Grading Plan:** Constructed grading plan showing the as-built graded condition of the site, including all finished elevations, slopes, drainage features, cut/fill limits, and site access after construction is complete.

## 5.4 Required Attachments (All Delivery Point Requests)

- Noteworthy Load Characteristics:** A summary of unique electrical characteristics of the load that could impact transmission system performance.
- Transformer Test Report(s):** Official factory or field test documentation verifying transformer performance, ratings, impedance, losses, and compliance with specified standards.
- Transformer Loss Curve:** A curve or data set showing transformer losses as a function of loading, used for system studies, efficiency analysis, and planning assumptions.
- Operating Procedures Description:** A narrative describing how the Customer intends to operate the facility, including normal, abnormal, startup, shutdown, and emergency conditions.
- Operating One-Line Diagram:** A standard electrical engineering diagram that shows the electrical configuration and how the requesting party is operating the power flow from the delivery point to the load, along with critical connections, protection components, and equipment ratings.

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6. **Protection Scheme Functional Diagram:** Detailed information on protective relays and devices, including manufacturer data and settings, needed to verify coordination and system protection compatibility.
7. **Protection Device Information:** Inclusive of Device Types, Serial and Model Numbers, and Relay Settings.
8. **Customer Load Models:** Phasor-domain dynamic composite load model (CMLD), modified EV Load Model (PERC1), and/or other user-defined model representing load facility in PSSE format. Can use a combination of these models to accurately represent both the mechanical and compute load at the site
9. **Catalog Sheet:** Manufacturer-provided technical specification sheets for major electrical equipment, detailed ratings, dimensions, performance characteristics, and standards compliance.

## 6.0 REVISION HISTORY

**Table 18. Revision History**


Revision Date	Revision #	Description	Revised By	Effective Date
		The original document has been superseded by this Revision 1.0	ET Planning staff	
08/01/2024	1.0	See Details for Revision 1.0 below	Kristen Custer	09/01/2024
03/11/2025	2.0	See Details for Revision 2.0 below	Kristen Custer	04/01/2025
09/10/2025	3.0	See Details for Revision 3.0 below	Kristen Custer	10/01/2025
03/01/2026	4.0	See Details for Revision 4.0 below	Thomas Mconnell and Danovo Energy Solutions	04/01/2026

### Details for Revision 1.0

- Revision contributors include Aaron Winter, Colleen Wallace, Harrison Potter, Keith Graham, Amirreza Sahami, Rahul Chakraborty, Kristen Custer, and Quanta Technology.
- The Customer Request Form has undergone a complete re-write and supersedes the original form, which was included in the last revision of the Facility Interconnection Requirements document package.
- Instructions revised to reflect the new process of using the web-based Delivery Point Exchange for submittal and status review of customer requests.
- Form has been revised to request more specific customer information, including additional data describing anticipated demand.
- Creation of Noteworthy Load Characteristics Form intended to obtain more detailed data to support planning studies.

### Details for Revision 2.0

- Revision contributors include the following: Jonathan Deverick, Aaron Trump, Katelynn Vance, Kristen Custer, Keith Graham, and Quanta Technology.
- Document formatting (fonts, margins, etc.) updated to improve readability. Changed the main font from Arial to Aptos.
- Updated Abbreviations and Acronyms.
- Acronyms moved to the front of the document to align with the main FIR document.
- Grammatical modifications including capitalization, spelling, punctuation, and consistency.

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- Renamed document from “Customer Request Form” to “Customer Delivery Point Requests”.
- Clarified use of the term “Customer Delivery Point” relative to “Customer Requests”
- Removed use of the term “generation” in the context of Customer delivery point requests
- Clarified expectations around new, revised, or modified delivery point requests.
- Added language around the timeline for changes to delivery point requests prior to energization.
- Added language around customer expectations to provide peak demand data at the most granular level available, system protection design of end-use facilities, and modeling data requirements.
- Formatted existing content by removing the “Part” sequencing into data tables for new delivery point information, present delivery point information, customer timing, and anticipated peak customer demand.
- Removed “Part 1: Delivery Point Submittal Information.”
- The request type now includes New Delivery Point Information and Present Delivery Point information. This information was in separate sections in prior versions.
- Merged anticipated peak demand tables to be common for New Delivery Point information and Present Delivery Point information
- Added new questions around the delivery point request information.
- Moved Noteworthy Load characteristics section ahead of Customer equipment section.
- Added clarifying comments and additional data fields to the Data Center Noteworthy characteristics section.
- Added section on customer equipment with required attachments.
- Included requirement for PSSE Dynamic models to support simulation studies.
- Moved “Requirement of Authorization” to the end of the document.

#### **Details for Revision 3.0**


- Revision contributors include Kristen Custer, Keith Graham, and Quanta Technology.
- Editorial updates (grammar, spelling, punctuation, capitalization), consistency improvements in terminology, refinements to instructions, minor adjustments to tables/fields, and formatting changes for clarity and alignment with the main FIR.

#### **Details for Revision 4.0**

- Revision contributors include Keith Graham, Thomas McConnel, Sarah Craig, Harrison Potter, Jacki Vitiello, PwC, and Danovo Energy Solutions.
- Re-organized the FIR Attachment 2 to align with the new DPR process project stages: Initiation, Feasibility, Development, and Execution.
- Added detail of the new DPR queue management process, within Initiation, to include details on batch assignments and re-assignments and the Acknowledgement of Intent (AOI) process to leave Initiation and progress to Feasibility.
- Added the list of required attachments and actions, and their associated descriptions, for both data center DPRs and all types of DPRs for each project stage.
- Moved Noteworthy Load Characteristic sections and required tables to the Execution stage section to better align with when an EDC would provide this information to DEV.
- Editorial updates (grammar, spelling, punctuation, capitalization), consistency improvements in terminology, refinements to instructions, minor adjustments to tables/fields, and formatting changes for clarity and alignment with the main FIR.
- Capitalized “Customer” throughout the document to align with the first paragraph.

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- Changed “EDC” to “Customer” throughout to align with the first paragraph.
- Changed “delivery point request” to “DPR” throughout except for in titles, tables, and the revision history.

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# Attachment 3

## Generator Interconnection Protection Requirements

**Dominion Energy Virginia—Electric Transmission  
Facility Interconnection Requirements**

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## ABBREVIATIONS AND ACRONYMS

Term	Definition
<b>CCVT</b>	Coupling Capacitor Voltage Transformer
<b>COMTRADE</b>	Common Format for Transient Data Exchange
<b>CT</b>	Current Transformer
<b>CVT</b>	Capacitor Voltage Transformer
<b>DCB</b>	Directional Comparison Blocking
<b>DEV-ET</b>	Dominion Energy Virginia Electric Transmission
<b>DFR</b>	Digital Fault Recorder
<b>DG</b>	Distributed Generation
<b>DP</b>	Delivery Point
<b>FIR</b>	Facility Interconnection Requirements
<b>GSU</b>	Generation Step-up Transformer
<b>IBR</b>	Inverter-based Resource
<b>IEEE</b>	Institute of Electrical and Electronic Engineers
<b>MW</b>	Megawatt
<b>N-1</b>	Single Contingency Outage (Normal-minus-one Transmission Element)
<b>NERC</b>	North American Electric Reliability Corporation
<b>OPGW</b>	Optical Ground Wire
<b>PCC</b>	Point of Common Coupling
<b>POI</b>	Point of Interconnection
<b>PJM</b>	PJM Interconnection
<b>PLC</b>	Power Line Carrier
<b>RMS</b>	Root-mean-square
<b>RTO</b>	Regional Transmission Organization
<b>SIR</b>	Source Impedance Ratio
<b>TDD</b>	Total Demand Distortion
<b>THD</b>	Total Harmonic Distortion
<b>UTC</b>	Coordinated Universal Time
<b>VA</b>	Volt-ampere

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## DEFINITIONS

Term	Definition
<b>Breaker Failure Transfer Trip</b>	Trips remote sources in the event of a breaker failure.
<b>Customer-interconnected Generation Station (or Customer-interconnected Collector Station)</b>	Customer-owned substation containing line or collector line terminals, breakers, and transformers, as well as protection, metering, and monitoring equipment.
<b>Dominion Energy-interconnected Switching Station</b>	DEV-ET-owned substation containing line terminals, breakers, transformers, and protection, metering, and monitoring equipment. The DEV-ET Interconnected Switching Station is included as a line terminal transmission substation.
<b>Islanding Transfer Trip</b>	Trips interconnection in the event that a generating facility is operating disconnected from the transmission grid.
<b>Line Transfer Trip</b>	Trips are remote sources that are not capable of clearing a fault because the current magnitude is below the protective relay scheme setpoints.
<b>N-1</b>	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.
<b>Networked Transmission Line</b>	A transmission line that connects to two or more network transmission sources (lines and/or substations).
<b>PJM</b>	RTO, of which DEV-ET is a member ( <a href="http://www.pjm.com">www.pjm.com</a> ).
<b>Power Line Carrier</b>	A higher-frequency signal coupled to the AC transmission system is used to transmit one bit of information.
<b>Radial Transmission Line</b>	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) or generation source.
<b>Transmission Element</b>	Transmission elements are primary equipment (69 kV and above) that constitute or interconnect with the Dominion Energy Electric Transmission System. Examples include buses, lines, or transformers with a low-side voltage of 69 kV or above, regardless of Bulk Electric System status.
<b>Transmission Tap Line</b>	A transmission tap line is defined as a radial line that connects to either a network or a radial transmission line.

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## 1.0 PURPOSE AND INTRODUCTION

Virginia Electric and Power Company is commonly referred to as DEV-ET.

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 DEV-ET's electric transmission system.

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

This document supplements DEV-ET's Facility Interconnection Requirements (FIR) document.

## 2.0 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. DEV-ET will require the installation of transfer trip equipment on all lines contained within the identified transfer trip boundary. The transfer trip boundary is expanded from the point of interconnection (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 toward meeting the criteria. The line connecting to the substation, which satisfies the boundary requirement, also requires a 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

DEV-ET will require the application of its anti-islanding protection standard at all Customer-interconnected switching stations. DEV-ET's anti-islanding protection standard requires each breaker or terminal's status within the anti-island boundary to be sent to DEV-ET'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 generators from energizing transmission elements within the islanding 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 the 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 (PLC)

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where existing fiber is unavailable and PLC is an acceptable transmission method (see Section 4.1 for more details).

### 3.0 INTERCONNECTION PROTECTION REQUIREMENTS

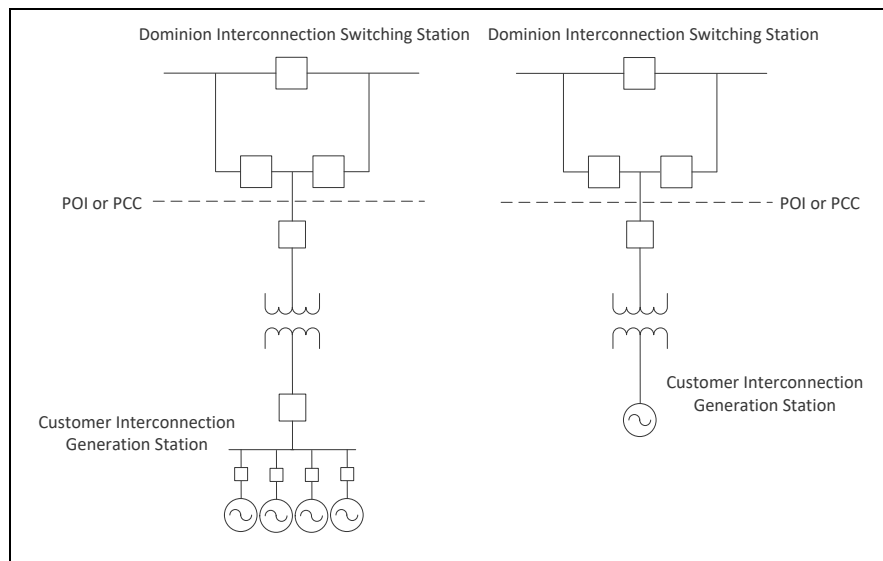
Interconnection protection requirements include specifications for fault protection of the interconnection line, breaker failure and reclosing, generation step-up transformers, and instrument transformers. Determination of the necessary protection for the POI is dependent on the individual and aggregate 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). To ensure the reliability of the transmission system, this configuration, shown in Figure 1, is required for a POI at any network transmission line on DEV-ET's transmission system.

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



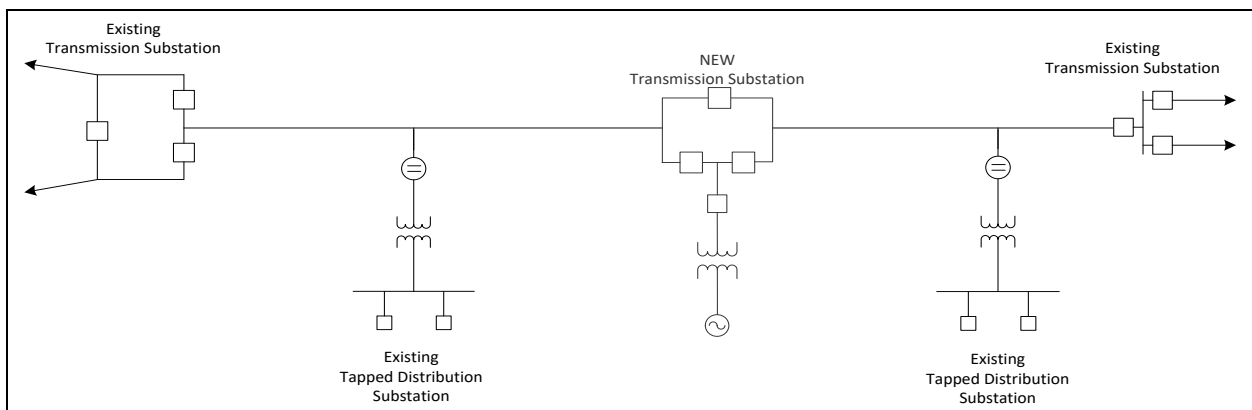
**Figure 1. Complex (Left) and Simplified (Right) Customer Interconnection Generation Station**

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### 3.1.1 Networked Transmission Line Interconnection

The DEV-ET Interconnection Switching Station will be a three- or four-breaker ring or comparable layout as outlined in Section 2 of the main document [1] for generation resources of any MW size that connect to a network transmission line. Proposed generating Facilities connecting to the Transmission System must not form multi-terminal lines. Multi-terminal lines are created when more than two sources are connected directly to a transmission line. Multi-terminal transmission lines created by proposed generating Facilities are prohibited regardless of the generating Facility capacity.

A breaker station ring ensures separation in zones of protection between the DEV-ET 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 Radial Transmission Line Interconnection

The DEV-ET Interconnection Switching Station may be a single breaker. However, generation resource POIs on radial transmission lines in DEV-ET’s transmission system must be considered on a case-by-case basis to evaluate the 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.

Proposed generating Facilities must be reviewed to ensure that they will not form multi-terminal lines. Multi-terminal lines are created when more than one generating Facility is connected directly to a transmission line. Multi-terminal transmission lines created by proposed generating Facilities are prohibited.

### 3.1.3 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 the POI. See Table 1 for further details.

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**Table 1. Ring Bus Considerations**

Merits	Ring Bus Connection	Single Breaker Connection on Radial Line
<b>Advantages</b>	<ul style="list-style-type: none"> <li>• Increased reliability, as the generation resource would have two outlets to deliver power. An outage on the networked line would only remove one side of the ring and still allow generation.</li> <li>• More uptime for the generation of resources leads to higher revenue.</li> <li>• Initial cost savings for no utility-owned breaker at the POI.</li> </ul>	<ul style="list-style-type: none"> <li>• Possible decrease in initial capital cost for not building a line back to the networked transmission line.</li> </ul>
<b>Disadvantages</b>	<ul style="list-style-type: none"> <li>• Possible increase in initial capital cost for building a line back to a networked transmission line.</li> </ul>	<ul style="list-style-type: none"> <li>• Decreased reliability, as the generation resource would only have one outlet to deliver power. An outage on the tap line would remove the generation resource from the service and not allow generation.</li> <li>• Less uptime for the generation resource leads to lower revenue.</li> <li>• Additional cost for utility-owned breaker at the POI.</li> </ul>

### **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.

The interconnection Customer must ensure that GSU high-side leads are not tapped for any reason. The GSU high-side leads are defined as the protection zone between the GSU high-side and the transmission breakers.

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See Section 3.7 for more details concerning the modeling of GSUs.

### 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 POI.

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 DEV-ET. 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) share the CT secondary circuit with a protective relay, the total burden of all secondary devices and conductors will not exceed 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 conductors 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 VA. 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 are connected to any CCVT (metering or protection class), protective relays will be connected to separate secondaries on the CCVT.

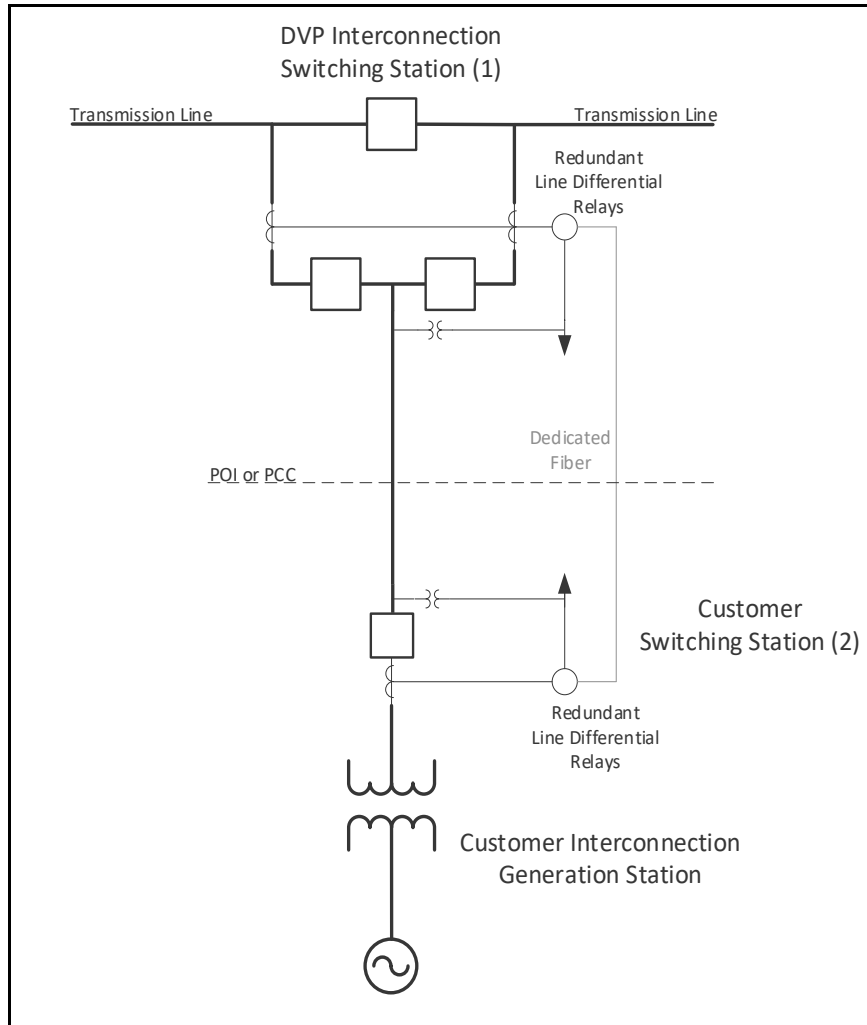
### 3.4 Transmission Elements Requirements

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 Interconnection Zone 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 one-line diagram equivalent in Figure 3. Additionally, 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 DEV-ET Interconnection Switching Station (1) and the Customer Switching Station (2). Customers should contact DEV-ET prior to purchasing protective relaying and fiber optic equipment and materials that it plans to use to interface with DEV-ET to obtain DEV-ET’s latest specifications; this is to ensure that Customers purchase equipment and materials that are compatible with DEV-ET’s facilities.


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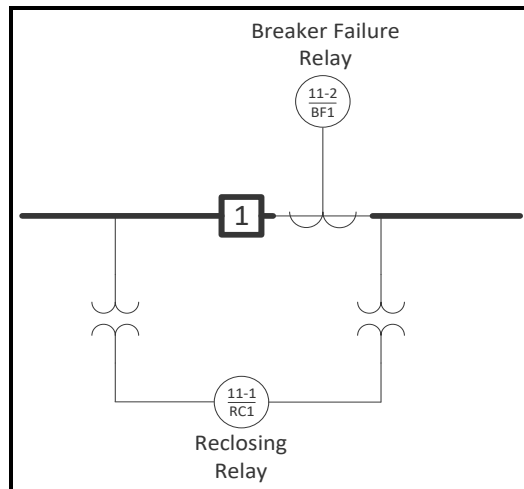


**Figure 3. Interconnection Zone of Protection**

### 3.5 Breaker Failure and Reclosing Equipment

Separate breaker failure and reclosing relays (Figure 4) will be installed on all transmission breakers (the Customer-owned high-side GSU breaker will only require breaker failure). All breaker failure relays will be required to send transfer trips to remote stations. A reclosing synchronism check will be performed prior to the breaker closing for all time-delayed reclosing attempts.

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**Figure 4. Breaker Failure and Reclosing Relays**

### 3.6 Mandatory Protective Relay Element Coordination

Per North American Electric Reliability Corporation (NERC) Reliability Standard PRC-027, all protective relay elements subject to the standard must be analyzed by DEV-ET 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 DEV-ET in an electronic form at least 45 days prior to energization. The Customer will clearly identify any protective relay elements that can detect faults in the DEV-ET 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 DEV-ET transmission system, DEV-ET, 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, DEV-ET will respond in a timely manner to communications requesting reviews of protective relay element coordination with its system.

The Customer will provide DEV-ET with long-term contact information for a person or group of people whom DEV-ET can reliably contact with respect to protective relays if the need should arise. This contract will be valid in perpetuity for as long as the Customer’s Facility is connected to the DEV-ET transmission system. Failure to respond in a timely manner to inquiries sent to the last known good contact for a facility may result in DEV-ET reporting the Customer’s Facility to SERC for violation of NERC Reliability Standard PRC-027. The Customer is responsible for providing DEV-ET 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.

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### 3.7 Electrical Models of Customer Facilities

To support the coordination of protective relay elements and accuracy of DEV-ET’s short circuit, planning, and operational models of the transmission grid, the Customer will provide DEV-ET 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 DEV-ET 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 DEV-ET at least 45 days prior to energization. The electrical models will be sufficiently detailed such that DEV-ET 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, the following:

- Step up transformer impedance.<sup>1</sup>
- 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, the unit impedances and grounding impedance.
- For asynchronous generation, the inverter make and model, and a functionally accurate model of the inverter’s controls during dynamic and short circuit system conditions.


DEV-ET 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.

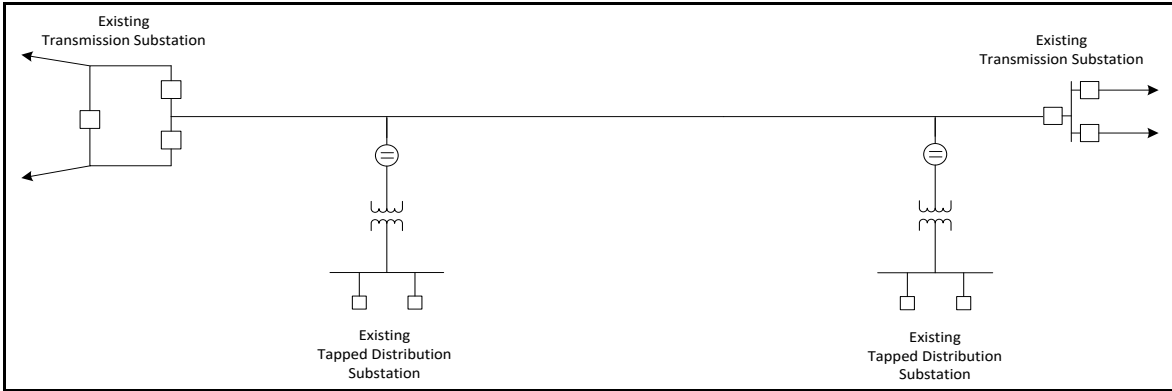
### 4.0 IMPACT OF NETWORKED TRANSMISSION LINE SPLIT ON LINE TERMINAL PROTECTION

In many cases, interconnection switching stations are built near an existing transmission line (Figure 5), resulting in the existing transmission line being split into two shorter transmission lines (Figure 6). The two shorter transmission lines may require protection modifications due to PLC or relaying constraints (e.g., a medium-length line now becomes two short-length lines).

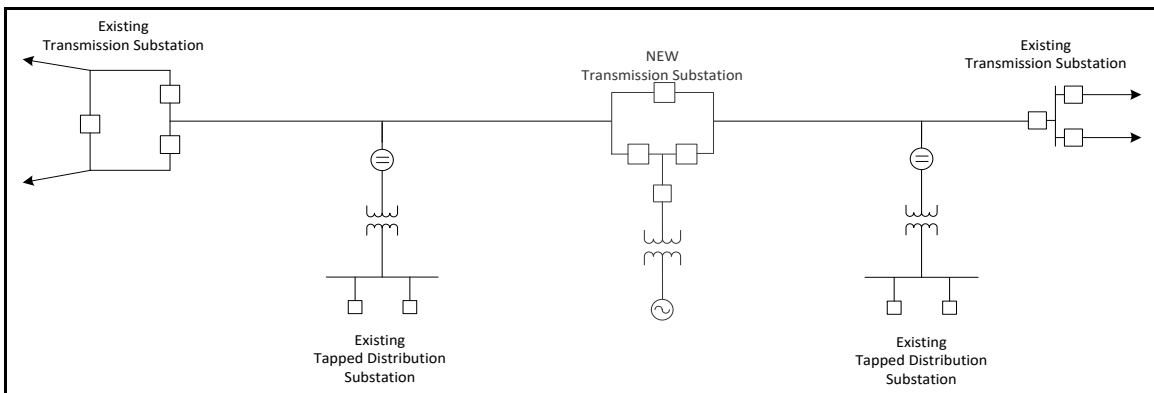
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<sup>1</sup> For generation step-up transformers (the transformers connecting generation to the transmission system), a frequent choice for the transformer’s winding configuration is a grounded wye-grounded wye with a buried delta tertiary winding. 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. DEV-ET 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.

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**Figure 5. Existing Transmission Line**

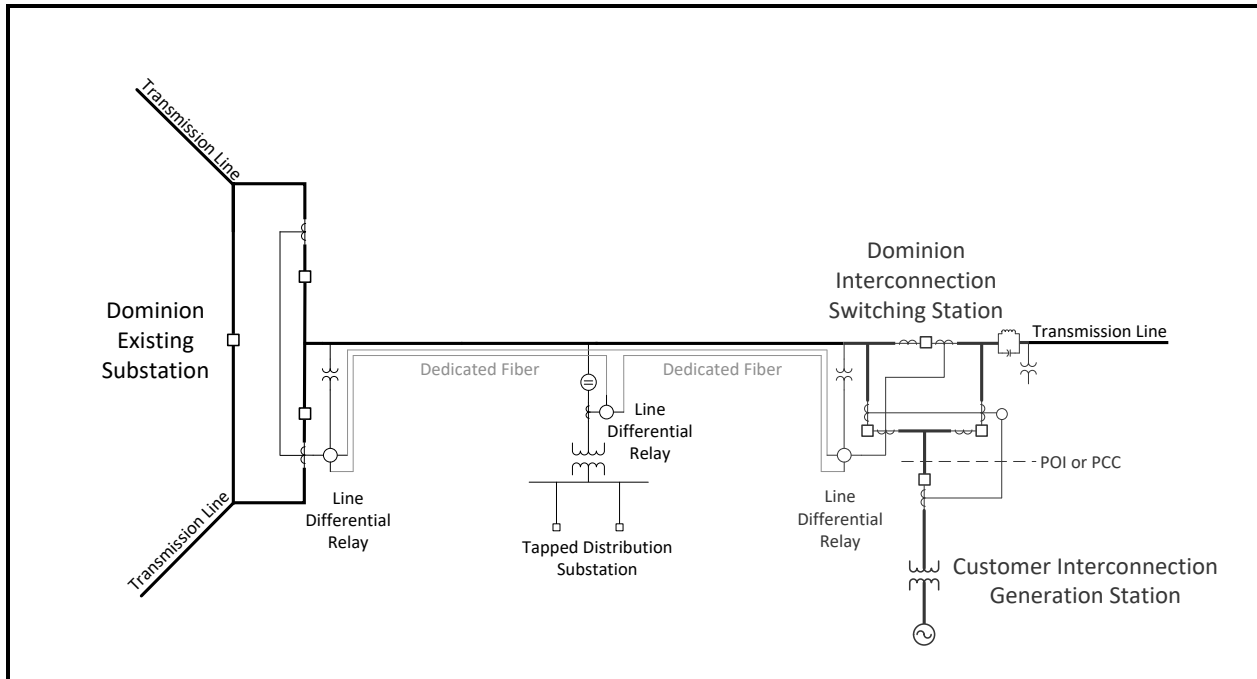


**Figure 6. Transmission Line Split**

#### 4.1 Short Transmission Line Protection

Short transmission lines and line segments less than 5 miles will be protected using dual-line current differential relays. Line current differential relays require dedicated fiber to be available between the line and tap terminals. Relaying constraints permit the allowance of 1 tapped distribution substation within the line differential, as shown in Figure 7.

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**Figure 7. Short Line with Fiber**

When a direct fiber connection is not available between the interconnect station (DEV-ET Interconnection Switching Station), remote terminal station (DEV-ET Existing Substation), and tapped distribution station, modifications to the lines, structures, towers, conduits, terminating and other equipment may be required to accommodate a direct fiber connection between the interconnect substation, existing remote substation, and tapped distribution substation. Shown in Figure 8, 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 to 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 9. In summary, the 5-mile requirement is between a location with a PLC transmitter and a location with a PLC receiver.

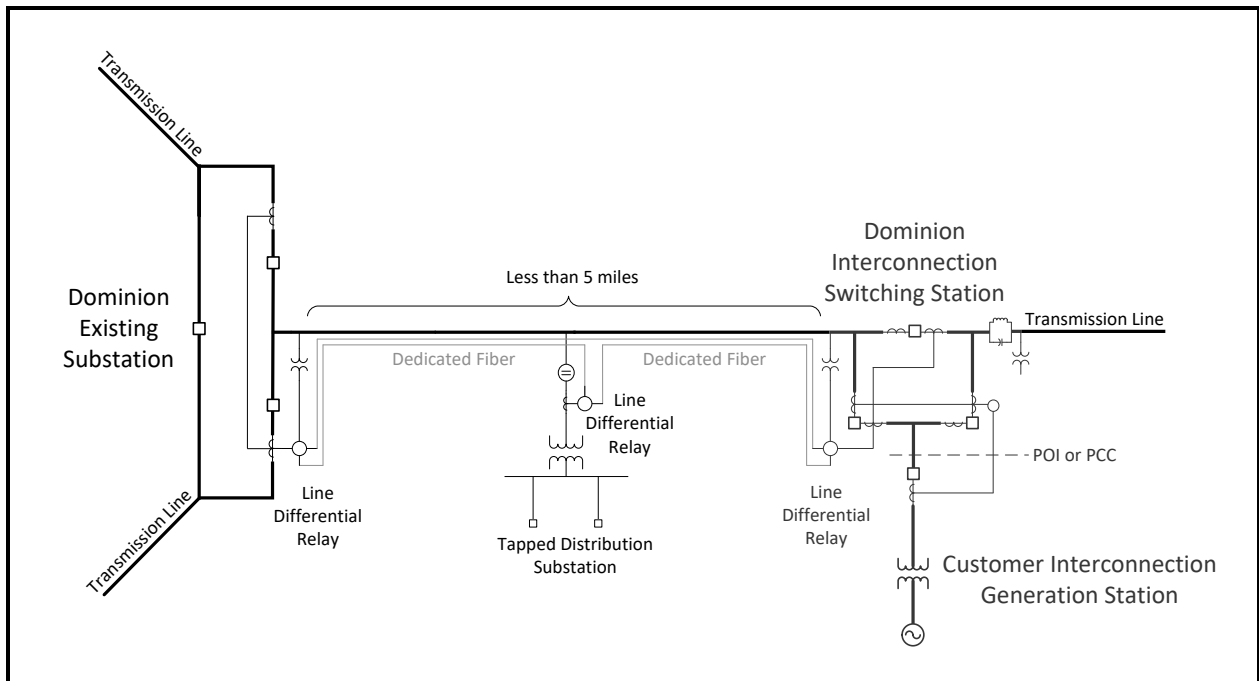
PLCs will not be used on transmission lines less than 5 miles long to maintain a high level of protection system dependability. PLC systems coupled to short transmission lines have low signal attenuation, causing several problems. Most prominently, low signal attenuation results in high voltage standing wave ratios and can cause carrier beating between opposite terminal PLC equipment [3, 4]. Carrier beating results in the PLC strength oscillating between 0–2 times rated power, resulting in PLC 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]. The SIR is the ratio of Thévenin's equivalent source


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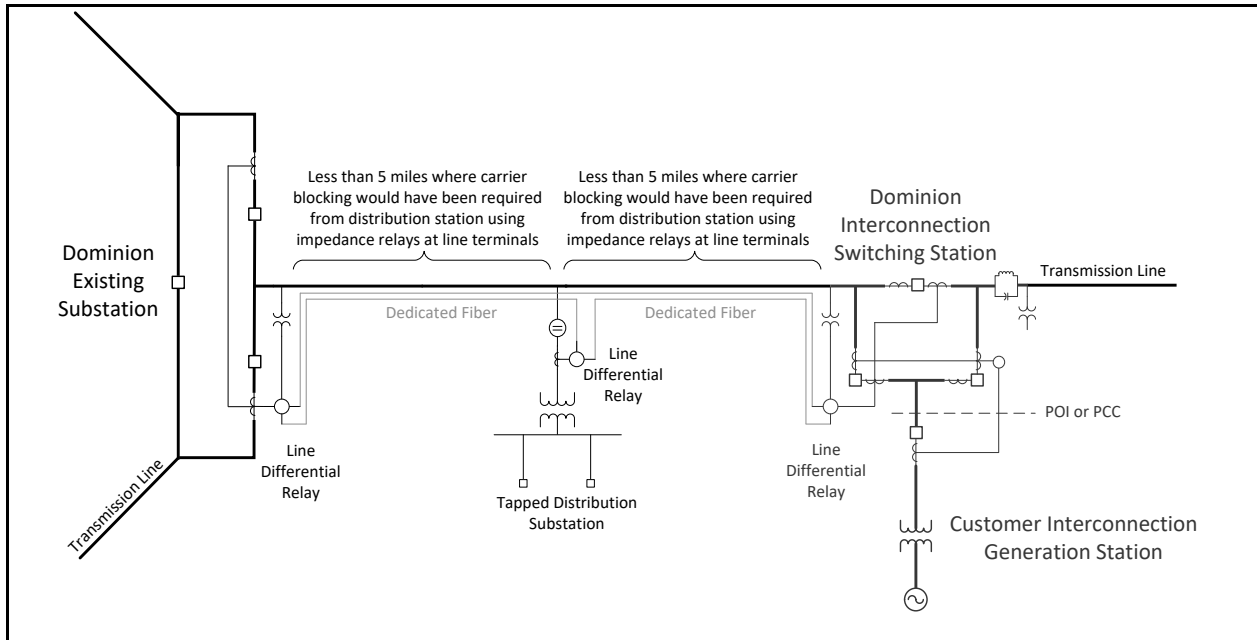
impedance to the line impedance. Short lines protected by impedance relays are subject to transient overreach due to suppressed voltage measured at the relay and transient instrument and relay errors [6].

For short transmission lines with tapped loads requiring communication with line terminals, a fiber optic drop must be installed at the delivery point (DP) to facilitate Line Transfer Trips for distributed generation (DG) applications or to send Breaker Failure Transfer Trip signals. In cases where the tap is made to a radial transmission line, a fiber optic drop is always required to ensure reliable communication and operational integrity.



**Figure 8. Traditional Zone of Protection for a Short Line**

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**Figure 9. Medium Line Requiring Carrier Blocking at Distribution Substation Follows Short Line Requirements**


#### 4.2 Medium and Long Transmission Line Protection

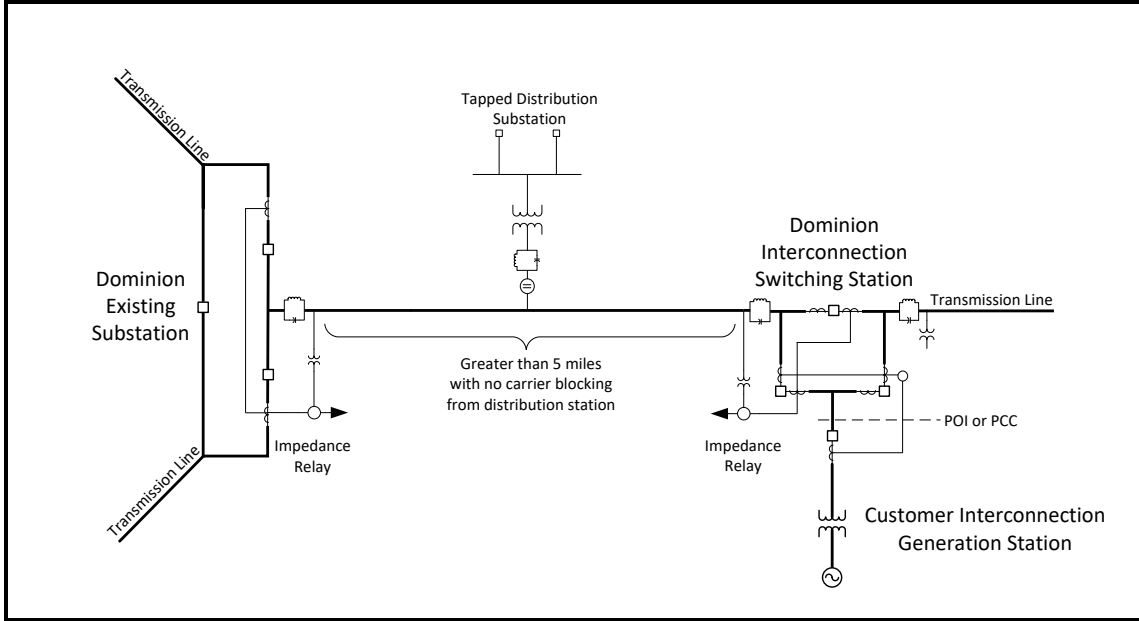
Medium and long transmission lines longer than 5 miles will be protected using either dual impedance or dual differential relays.

If fiber is already available on a transmission line, DEV-ET, at its sole discretion, may require Customers to upgrade existing impedance relays to differential relays at both terminals to mitigate the effects that IBRs have on fault detection and directionality detection by protection relays.

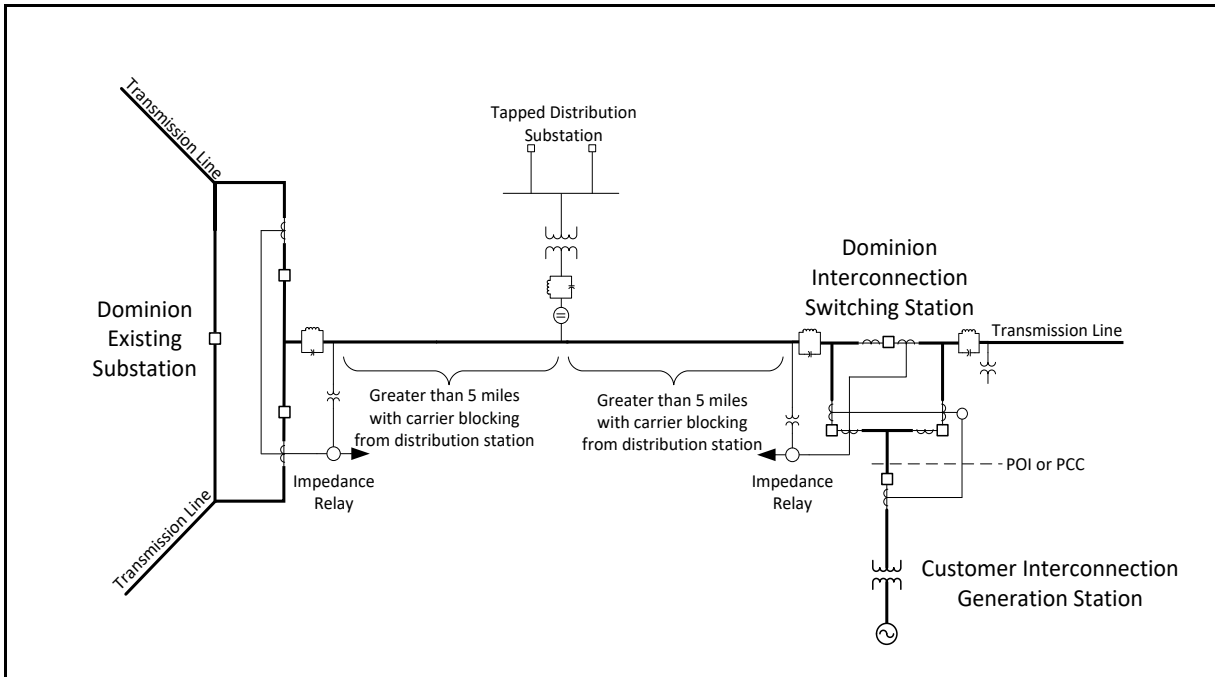
In cases where fiber exists on a line, but the line has a tapped distribution station that does not need carrier blocking at the tapped substation, DEV-ET, at its sole discretion, may require Customers to upgrade existing impedance relays to new impedance relays at both terminals that can accommodate a directional comparison blocking (DCB) scheme or another communication-aided scheme over fiber to help mitigate the effects of IBRs.

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 a PLC may be specified. Regardless, Customers will not be required to install fiber on transmission lines where the total length or the length of all line segments is longer than 5 miles.


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**Figure 10. Medium or Long Transmission Line Zone of Protection**



**Figure 11. Medium or Long Transmission Line Zone of Protection with Carrier Blocking Tap**

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## 5.0 POWER QUALITY PROTECTION AT POINT OF COMMON COUPLING

DEV requires that all generator interconnections install a device capable of monitoring power quality and tripping circuit breakers; see criteria listed in Institute of Electrical and Electronics Engineers (IEEE) Std 1159 [7] and other applicable standards. Power quality concerns associated with solar photovoltaic are reiterated in IEEE Std 2800 [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:

- Undervoltage (27): An undervoltage is an RMS decrease in AC voltage.
- Overvoltage (59): An overvoltage is an RMS increase in AC voltage.
- Under/Overfrequency (81/U, 81/O): Frequency deviations above or below nominal frequency.
- Reverse Power (32): Reverse power protection may be implemented as a supervisory function or to ensure contracted power agreements are not exceeded.
- Power Factor: Power factor requirements will be based on the contracted power factor agreement.
- Imbalance: Imbalance will be measured through differing phase quantities of voltage or current.
- Waveform Distortion: Waveform distortion is defined as a steady-state deviation from an ideal power frequency sinusoid characterized by the spectral content of the deviation. The five primary types of waveform distortion are DC offset, harmonics, inter-harmonics, notching, and noise.
- Harmonics: Voltage or current harmonics may be calculated in terms of total harmonic distortion (THD) or total demand distortion (TDD) as outlined in IEEE Std 519 [10]. New interconnections that are solely or include IBRs must also comply with IEEE Std 2800. The current distortion levels must remain within the limits in Section 8.2.1 of IEEE Std 2800.
- Voltage Fluctuations: Voltage fluctuations are defined as varying voltage between 0.95–1.05 per unit. Voltage flicker, an undesirable result of voltage fluctuations, may be measured or monitored using methods outlined in IEEE Std 1453 [11], which is an adoption of IEC 61000-4-15. IBR interconnections shall be subject to requirements and emission limits in Section 8.1.3 of IEEE Std 2800–2022.


DEV will determine during detailed design whether power quality tripping is needed.

## 6.0 DISTURBANCE AND POWER QUALITY MONITORING

Disturbance monitoring equipment must be independent of any protective equipment used for tripping outlined in Section 2.0 through Section 5.0. The power quality protection device installed per Section 5.0 will also satisfy the monitoring requirement, but an additional power quality monitoring device(s) can be installed; any additional power quality monitoring devices are not required to have tripping capability. Disturbance and power quality monitoring equipment must be time-synchronized to Coordinated Universal Time (UTC) with a satellite clock with a local UTC offset as appropriate based on equipment location.

## 7.0 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 4,800 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

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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.

- Customers must provide physical breaker failure lockout position for all GSU high-side breaker(s) to the utility’s DFR. The physical breaker status can be transmitted digitally to the interconnected transmission substation. This ensures the millisecond accuracy of the sequence of events report. Statuses for virtual lockouts are not acceptable
- Customers must provide breaker failure lockout position for all GSU high-side breaker(s) via physical contact with the utility’s DFR. This is to ensure millisecond accuracy of the sequence of events report.
- 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.

### 7.1 Phasor Measurement Units/Synchrophasor Requirements

Phasor measurement units are required at all interconnection substations to provide real-time synchrophasor data to DEV-ET’s synchrophasor system. PJM Manual 14D specifies that all generations greater than 100 MW must provide synchrophasor data to PJM’s synchrophasor system as well.

### 7.2 Power Quality Monitoring


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

### 7.3 Requests for Data from Customer Devices

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

## 8.0 REFERENCES

1. “Facility Interconnection Requirements,” Section 2.
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 Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems*, IEEE Std 2800, 2022.
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.

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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.

## 9.0 REVISION HISTORY

Revision Date	Revision #	Description	Revised By	Effective Date
7/16/2015	0.0	Document Creation	Christopher Mertz	-
8/17/2015	1.0	See Details for Revision 1.0	Christopher Mertz	01/01/2016
5/26/2017	2.0	See Details for Revision 2.0	Marlu Deverick	06/01/2017
12/11/2018	3.0	See Details for Revision 3.0	Douglas Ladd	01/1/2019
2/23/2021	3.1	See Details for Revision 3.1	Joseph Saylor	04/01/2021
02/10/2022	4.0	See Details for Revision 4.0	Daniel Ridenour	04/01/2022
02/16/2023	5.0	See Details for Revision 5.0	Daniel Ridenour	04/01/2023
08/01/2024	6.0	See Details for Revision 6.0	Daniel Ridenour / Quanta Services	09/01/2024
03/11/2025	7.0	See Details for Revision 7.0	Daniel Ridenour / Quanta Technology	04/01/2025
09/10/2025	8.0	See Details for Revision 7.0	Daniel Ridenour / Quanta Technology	10/01/2025

### Details for Revision 1.0


- Updated short-line requirement drawings to show fiber relaying at a tapped distribution station.
- Modified wording to exclude Customer-owned GSU breaker from the reclosing requirement.

### Details for Revision 2.0

- Revised references for the 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 the layout of several sections to improve the flow of material.

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#### Details for Revision 3.1

- Updated the signature page.
- Added Sections 3.6 and 3.

#### Details for Revision 4.0

- Minor formatting changes throughout the 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 the document.
- Removed Section 7; Attachment 5 now contains this information and additional detail.

#### Details for Revision 6.0

- Revision contributors include Daniel Ridenour, Jacob Midkiff, Micah Till, Aaron Winter, Colleen Wallace, Keith Graham, Mark Gill, Mohsen Mahoor, Peter Nedwick, and Quanta Technology.
- Removed signature page and consolidated on FIR cover 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 line taps that require carrier blocking.
- Revised Section 6 introduction to specifying that 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 the document.
- Updated reference from IEEE 929 to IEEE 2800.

#### Details for Revision 7.0


- Revision contributors include the following: Daniel Ridenour, Mike Yunik, Nedim Besirevic, Kristen Custer, Keith Graham, and Quanta Technology.
- Document formatting (fonts, margins, etc.) updated to improve readability. Changed the main font from Arial to Aptos.
- Updated Abbreviations and Acronyms.
- Acronyms moved to the front of the document to align with the main FIR document.
- Grammatical modifications, including capitalization, spelling, punctuation, and consistency
- Added language in Section 3.1.1 to not allow creation of multi-terminal lines
- Removed section on Transmission Tap Line Interconnection

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- Added language to Section 3.2 to prevent taps on high-side lead of the Generator Step-up transformers
- Moved language from Section 3.7 around GSU transformer winding configurations to a footnote.
- Added clarifications to Section 4.1 around fiber optic drop requirements for short transmission lines.
- Added clarifying comments to Section 5, referencing specific sections of IEEE Std 2800 for compliance.

#### **Details for Revision 8.0**


- Revision contributors include the following: Daniel Ridenour, Nancy Ashberry, Kristen Custer, Keith Graham, and Quanta Technology.
- Editorial corrections: grammar, spelling, punctuation, capitalization, and terminology consistency.
- Clarified generator step-up transformer (GSU) rules, including restrictions on high-side lead taps.
- Strengthened requirements for submission of complete and detailed electrical models.
- Clarified protection requirements for short transmission lines, emphasizing fiber optic drops at tapped points.  
Updated medium/long line protection language to align with inverter-based resource (IBR) standards.
- Expanded power quality protection section with cross-references to applicable IEEE standards (1159, 1453, 2800).
- Reinforced requirement that breaker failure lockouts be provided through physical contacts, not virtual signals.

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	<b>Attachment 4: Ride-through Requirements for Bulk Power System Resources</b>		
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# Attachment 4

## Ride-through Requirements for Bulk Power System Resources

**Dominion Energy Virginia—Electric Transmission  
Facility Interconnection Requirements**

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### Abbreviations and Acronyms

Term	Definition
<b>BPS</b>	Bulk Power System
<b>DEV</b>	Dominion Electric Virginia
<b>DEV-ET</b>	Dominion Electric Virginia—Electric Transmission
<b>IBR</b>	Inverter-based Resource
<b>NERC</b>	North American Electric Reliability Corporation

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## 1.0 RIDE-THROUGH REQUIREMENTS FOR BULK POWER SYSTEM RESOURCES

For bulk power system (BPS) resources, NERC Reliability Standard PRC-024 currently defines voltage and frequency ride-through requirements for both synchronous and non-synchronous generators—inverter-based resources (IBRs). PRC-024 is being modified to apply to synchronous machines only, and a new standard is being created for IBRs. As NERC requirements are created or modified, Dominion Energy Virginia—Electric Transmission (DEV-ET) expects Generator Owners to adopt new requirements and apply the most up-to-date version of existing requirements.

All synchronous and non-synchronous generation tied to DEV-ET’s system must respect DEV-ET’s voltage and frequency ride-through requirements. As the industry evolves and NERC requirements change, DEV-ET’s requirements may change. Generator Owners are expected to implement the changes when DEV-ET informs them of any new or updated requirements.

## 2.0 VOLTAGE RIDE-THROUGH

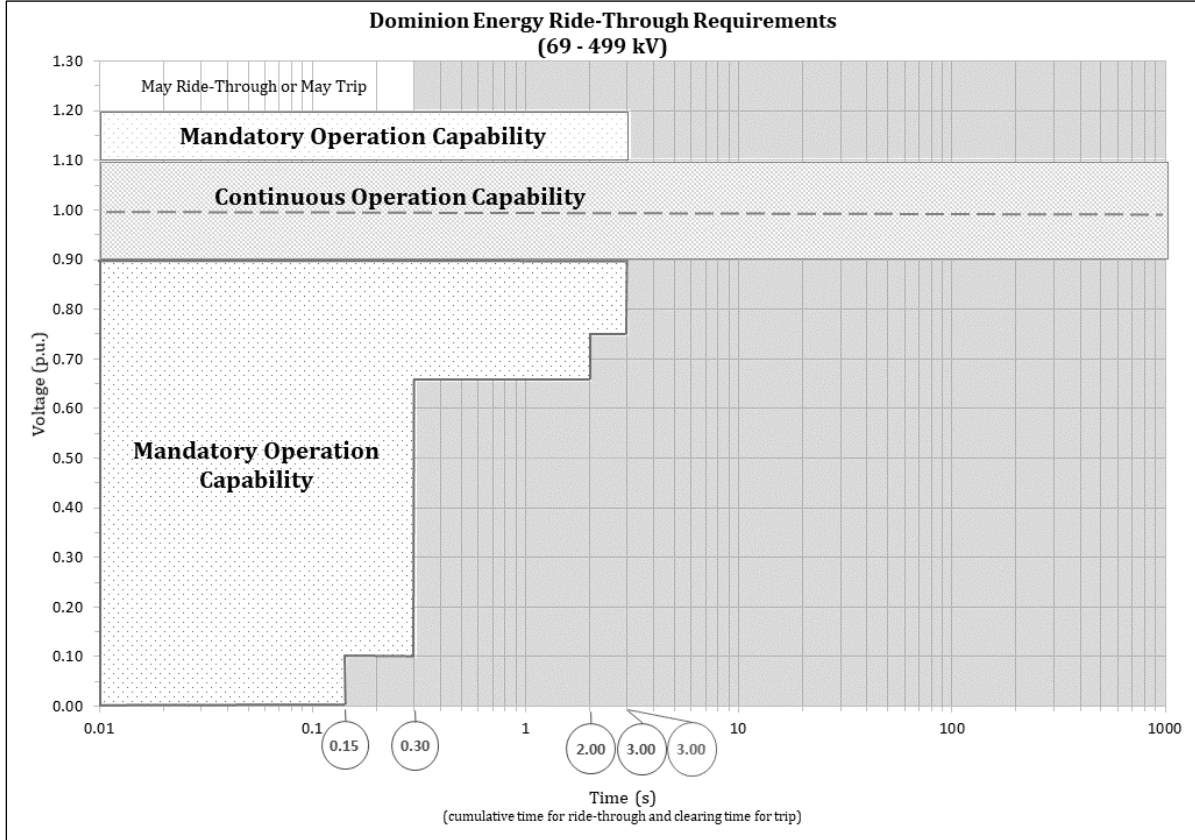
DEV-ET’s voltage ride-through requirements are derived from NERC Reliability Standard PRC-024 and other NERC guidelines. Table 1 lists the voltage operating point and minimum clearing times for generation connected to buses with a nominal voltage greater than or equal to 69 kV but less than 500 kV. These voltage operating points are plotted in Figure 1.

**Table 1. DEV-ET Ride-through Requirements (69 kV–499 kV)**

Voltage Range (pu)	Operating Mode	Minimum 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

In some instances, existing IBRs lack sufficient setpoints within the internal controls to match the setpoints listed in Table 1. When an existing IBR does not have enough setpoints, the longest ride-through time duration shall be retained for all thresholds of increasing severity. For example, if the inverter has only one low-voltage setpoint, the low-voltage ride-through duration shall be set to three seconds.

All new interconnections should have controls capable of meeting the requirements listed in Table 1.

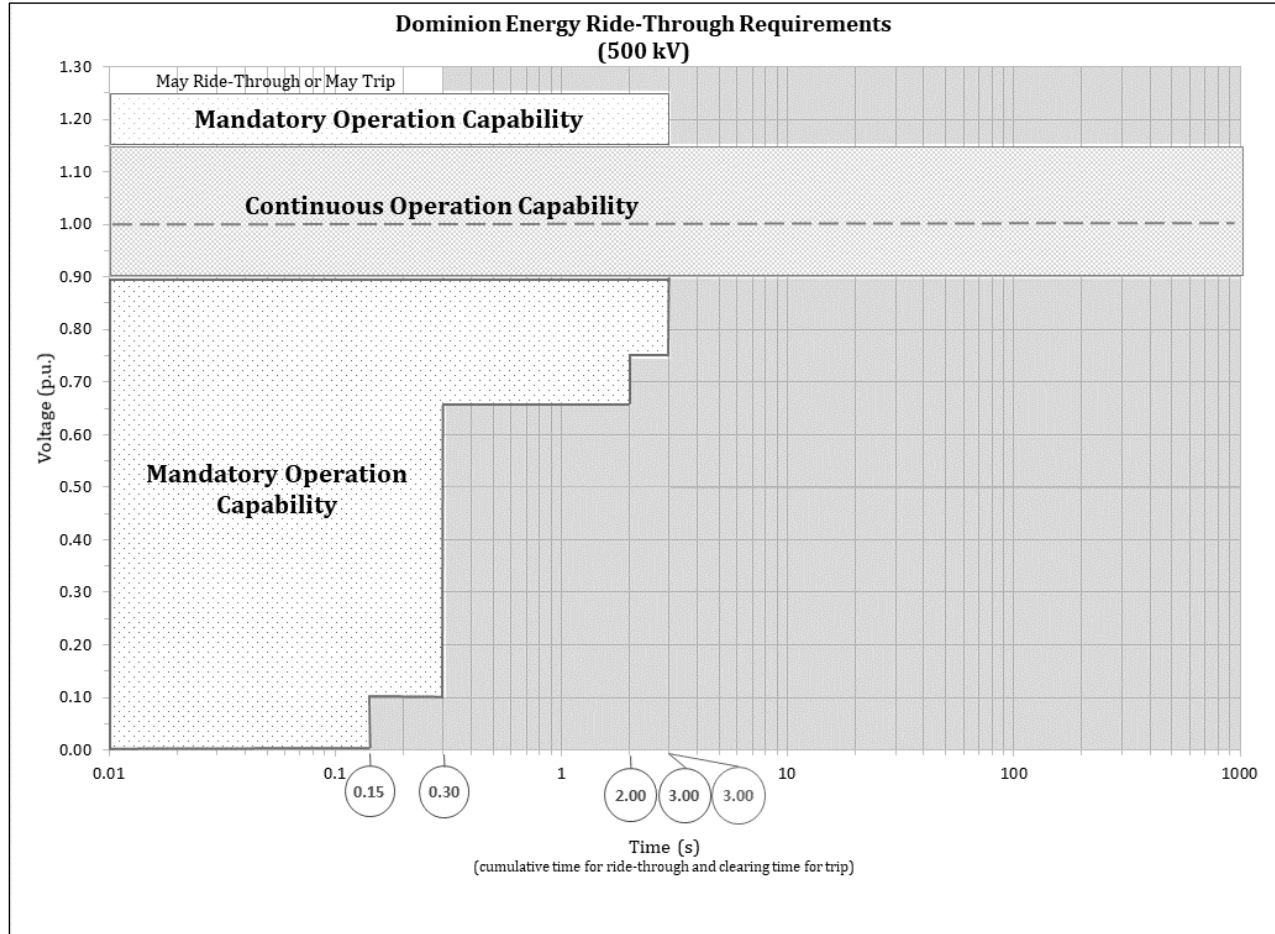


**Figure 1. DEV-ET Ride-through Requirements (69 kV–499 kV)**

Generators interconnecting at 500 kV must be able to continuously operate through 1.15  $V_{pu}$ , as DEV-ET operates the 500 kV system typically between 1.00  $V_{pu}$ –1.10  $V_{pu}$ . The operating points for generation and minimum clearing times connected to the 500 kV system are listed in Table 2 and are plotted in Figure 2.

**Table 2. DEV-ET Ride-through Requirements (500 kV)**

Voltage Range (pu)	Operating Mode	Minimum 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	$\infty$
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




**Figure 2. DEV-ET Ride-through Requirements (500 kV)**

DEV-ET requires generators to continue operating while the voltage is within the boundaries of the voltage ride-through curves shown in Figure 1 and Figure 2. DEV-ET does not restrict generators from operating outside the voltage ride-through curves. At a minimum, protection and controls should be set to make certain the generators meet the requirement and ride-through voltage excursions, but the actual set points should be the maximum and minimum voltage operating points available for the safe operation of the plant, even if those points are outside the voltage ride-through curve shown in Figure 1 and Figure 2.

### 3.0 FREQUENCY RIDE-THROUGH

DEV-ET’s frequency ride-through requirements adhere to NERC Reliability Standard PRC-024 and other NERC guidelines. 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, Attachment 1.

NERC Reliability Standard PRC-024 does not prevent generators from operating outside the frequency ride-through curves. At a minimum, the protection and controls should be set to make certain generators meet the

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requirement and continue to operate during frequency excursions. The actual protection and control systems should be set to the maximum and minimum frequency operating points available for the safe operation of the plant, even if those points are outside the Eastern Interconnection frequency ride-through curves shown in NERC Reliability Standard PRC-024, Attachment 1.

According to NERC, inverters should be able to operate in the frequency range between 57 Hz–63 Hz.<sup>1</sup> NERC Reliability Standard PRC-024 requires generators located within the Eastern Interconnect to operate, without tripping, between 57.8 Hz–61.8 Hz.<sup>2</sup> This implies that IBRs should, in general, operate at all frequencies between 57.8 Hz–61.8 Hz.

## 4.0 REVISIONS

**Table 3. Revisions**

Revision Date	Revision #	Description	Revised by	Effective Date
01/19/2021	1.0	Initial Creation of Document	Chris Mertz	04/01/2021
02/07/2022	2.0	Add Frequency Ride-through Requirements	Jiecheng Zhao	04/01/2022
02/27/2023	3.0	Updated Signature Page	Amirreza Sahami	04/01/2023
08/01/2024	4.0	See Details for Revision 4.0 Below	Kristen Custer	09/01/2024
03/11/2025	5.0	See Details for Revision 5.0 Below	Kristen Custer	04/01/2025
09/10/2025	6.0	See Details for Revision 6.0 Below	Kristen Custer	10/01/2025


### Details for Revision 4.0

- Revision contributors include Daniel Ridenour, Jacob Midkiff, Micah Till, Aaron Winter, Colleen Wallace, Keith Graham, Mark Gill, Mohsen Mahoor, Peter Nedwick, Ronnie Bailey, and Quanta Technology.
- Removed signature page and consolidated on FIR cover page.
- Added explanation at the beginning of the document with reference to PRC-024.
- Arranged document into two sections: “Voltage Ride Through” and “Frequency Ride Through”.
- In the “Voltage Ride-through” section. Added language about how to interpret the requirement.
- In the “Frequency Ride-through” section. Added language about how to interpret the requirement.
- Added language to frequency ride-through requirements.
- Added references to support requirements.

### Details for Revision 5.0

<sup>1</sup> NERC Inverter-based Resource Performance Guideline, Sept 2018


<sup>2</sup> NERC PRC-024, “Generator Frequency and Voltage Protective Relay Settings,” Attachment 1.

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- Revision contributors include the following: Andrea Pinceti, Kristen Custer, Keith Graham, and Quanta Technology.
- Document formatting (fonts, margins, etc.) updated to improve readability. Changed the main font from Arial to Aptos.
- Updated Abbreviations and Acronyms.
- Acronyms moved to the front of the document to align with the main FIR document.
- Grammatical modifications including capitalization, spelling, punctuation, and consistency
- Replaced Clearing Time(s) in Table 2 and Table 3 to reflect Minimum Clearing Time

**Details for Revision 6.0**


- Revision contributors include Nancy Ashberry, Kristen Custer, Keith Graham, and Quanta Technology
- Editorial updates: grammatical corrections, spelling, punctuation, and capitalization.
- Consistency improvements: updated Abbreviations and Acronyms; acronyms relocated to the front for alignment with the main FIR document
- Formatting updates: fonts, margins, and general readability improvements.

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# Attachment 5

## Generator Interconnection Data Communications and Data Exchange Requirements

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## ABBREVIATIONS AND ACRONYMS


Term	Definition
<b>AGC</b>	Automatic Generation Control
<b>BESS</b>	Battery Energy Storage System
<b>BOM</b>	Back of Module
<b>CCVT</b>	Coupling Capacitor Voltage Transformer
<b>CVT</b>	Capacitor Voltage Transformer
<b>D-CURVE</b>	Continuous Unit Reactive Capability Curve
<b>DE</b>	Dominion Energy
<b>DEGM</b>	Dominion Energy Generation Marketing
<b>DEV</b>	Dominion Energy Virginia
<b>DEV-ET</b>	Dominion Energy Virginia—Electric Transmission
<b>DNP</b>	Distributed Network Protocol
<b>EMS</b>	Energy Management System
<b>FIR</b>	Facilities Interconnection Requirements
<b>GHI</b>	Global Horizontal Irradiance
<b>GI</b>	Generator Interconnection
<b>GMS</b>	Generation Management System
<b>GPS</b>	Global Positioning System
<b>GSU</b>	Generation Step-up Transformer
<b>GVL</b>	Global Variable
<b>HPA</b>	HectoPascal
<b>I/O</b>	Input/Output
<b>MOC</b>	Market Operations Center
<b>MW</b>	Megawatt(s)
<b>MVAR</b>	MegaVAR(s)
<b>NERC</b>	North American Electric Reliability Corporation
<b>O&amp;M</b>	Operations and Maintenance
<b>OPGW</b>	Optical Ground Wire
<b>PCC</b>	Point of Common Coupling
<b>PID</b>	Proportional Integral Derivative
<b>POI</b>	Point of Interconnection
<b>PJM</b>	PJM Interconnection
<b>POA</b>	Plane of Array
<b>PPA</b>	Power Purchase Agreement
<b>PPC</b>	Power Plant Controller
<b>PQM</b>	Power Quality Meter
<b>PV</b>	Photovoltaic
<b>RQM</b>	Revenue Quality Meter
<b>RTAC</b>	Real-time Automation Controller
<b>RTO</b>	Regional Transmission Organization

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Term	Definition
<b>RTU</b>	Remote Terminal Unit
<b>SCADA</b>	Supervisory Control and Data Acquisition
<b>SCU</b>	System Control Unit
<b>SEL</b>	Schweitzer Engineering Laboratories
<b>SOC</b>	Systems Operations Center

## DEFINITIONS

Term	Definition
<b>Automatic Generation Control</b>	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.
<b>Breaker Failure Transfer Trip</b>	Trips remote sources in the event of a breaker failure.
<b>Dominion Energy Generator Interconnect Station</b>	DEV-owned substation containing line terminals, breakers, transformers, protection, metering, and monitoring equipment. The DEV Interconnected Switching Station is included as a line terminal transmission substation.
<b>Generator Collector Station</b>	Customer-owned substation containing line or collector line terminals, breakers, and transformers, as well as protection, metering, and monitoring equipment.
<b>Gross Metering</b>	Metering is measured at the direct output of the generator and does not factor in losses due to auxiliary station service loads, transformer losses, and transmission line losses.
<b>Inverter Online</b>	The operational state where the inverter is grid-connected (producing AC real power) and can produce reactive power output if directed to do so by the PPC.
<b>Islanding Transfer Trip</b>	Trips interconnection in the event that a generating facility is operating disconnected from the transmission grid.
<b>Line Transfer Trip</b>	Trips are remote sources that are not capable of clearing a fault because the current magnitude is below the protective relay scheme setpoints.
<b>Net Metering</b>	Metering is measured at the POI with DEV, where all auxiliary station service loads, transformer losses, and transmission line losses are compensated.
<b>Night VARs</b>	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.
<b>No Load Reactive Support</b>	An operational mode for certain wind turbines in cases where there is insufficient wind to generate real power output, the turbine can still produce reactive power output.
<b>Off</b>	The operational state where BESS is not online and is not ready to perform a charge or discharge cycle.
<b>PJM Interconnection</b>	An RTO, of which DEV is a member ( <a href="http://www.pjm.com">www.pjm.com</a> ).
<b>Proportional Integral Derivative</b>	PID controllers use a control loop feedback mechanism to control process variables.

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<b>Term</b>	<b>Definition</b>
<b>Standby</b>	The operational state where the BESS is online but is currently in between charging and discharging cycles and is sitting idle.
<b>System Control Unit</b>	For inverters that operate in a skid configuration, the SCU acts as a centralized controller for the entire skid.
<b>Turbine Online</b>	The operational state where the wind turbine is grid-connected and can produce AC real power output if there is sufficient wind.

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## 1.0 PURPOSE AND INTRODUCTION

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

The purpose of the *Dominion Energy Virginia—Electric Transmission (DEV-ET) Generator Interconnection (GI) Data Communication and Data Exchange Requirements* document is to provide data communications architecture, data exchange, and standard supervisory control and data acquisition (SCADA) application requirements and expectations to any individual or group seeking to connect electric power generation to DEV’s electric transmission system.

A primary driver for these requirements is ensuring operational visibility of the interconnected facility to PJM, the Dominion Systems Operations Center (SOC), the Dominion Market Operations Center (MOC)/Dominion Energy Generation Marketing (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 by this document are for renewable energy generation, such as 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 DEV-ET’s Facility Interconnection Requirements document.


## 2.0 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 two to 2–4 GI substations, depending on the site configuration, type, and operating agreement with DEV. The standard overall communications architecture between the GI substation and the attached generation facility is depicted in Figure 1.

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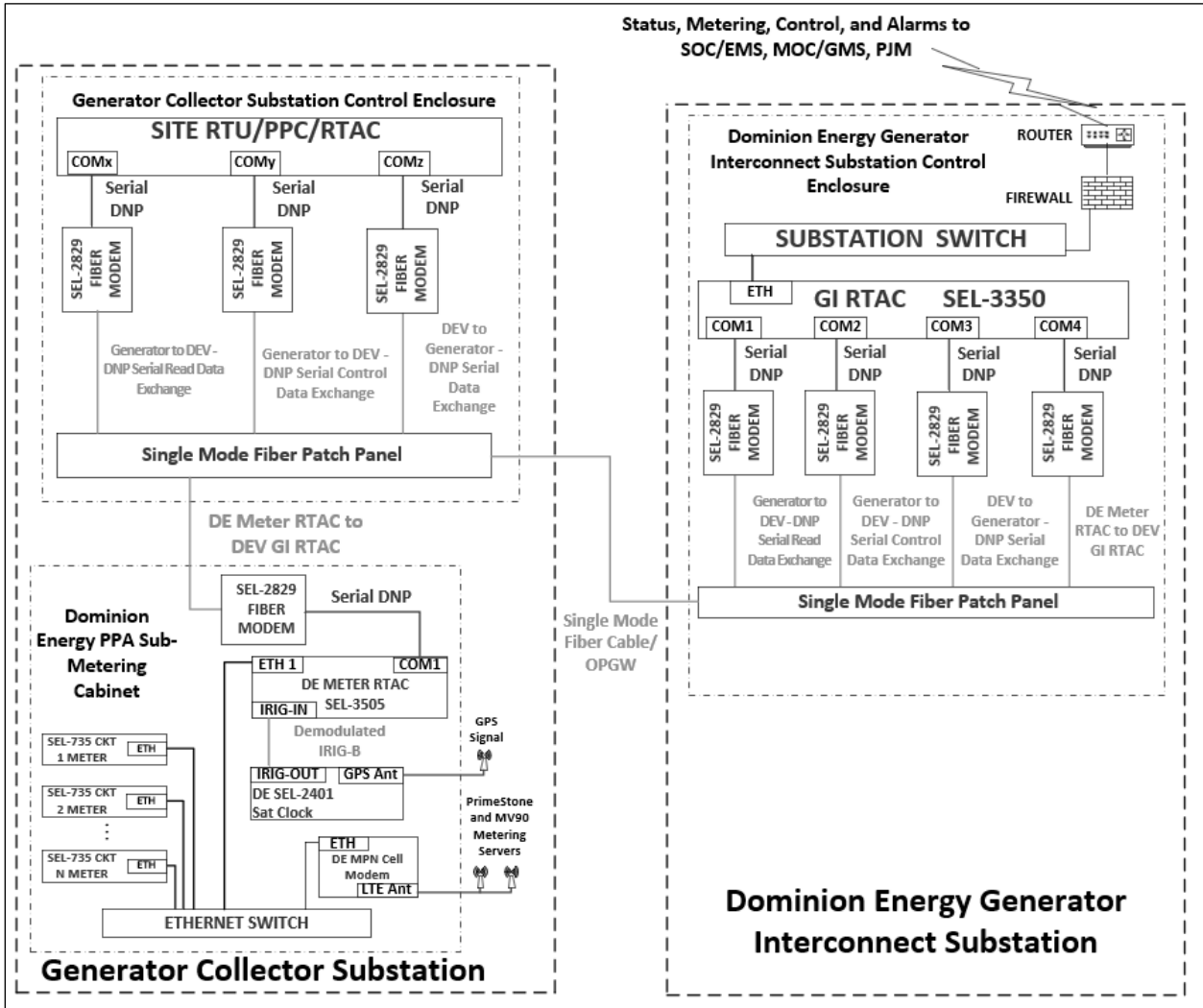



Figure 1. GI Substation to Generation Facility Overall Communications Architecture

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—GI Protection Requirements. This is the same fiber bundle also used for the line differential protection scheme on separate fiber pairs from the communications links. The communications method/protocol will be serial Distributed Network Protocol (DNP)-3 over single-mode fiber using Schweitzer Engineering Laboratories (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 the fiber bundle, there will be a single-mode fiber patch panel where the fiber pairs are terminated; individual connections will patch from

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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 the DNP Serial. The universal DNP map for this link is defined in a Microsoft Excel spreadsheet that is available upon request. 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, and 1 Stop Bit. The DNP client address must be 100, and the DNP server address must be 1. The GI real-time automation controller (RTAC) is the DNP client device, and the Site remote terminal unit (RTU)/power plant controller (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 DEV.

### 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 are required by PJM, DEV SOC, DEV MOC, and 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, and 1 Stop Bit. The DNP client address must be 100, and the DNP server address must be 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 historicization. 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, and 1 Stop Bit. The DNP Client Address must be 100, and the DNP Server Address must be 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 DEV.

### 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 DEV-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 DE 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

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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 cybersecurity requirements.

### 3.0 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 Sections 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 DE to be used by Data Communication Engineering. For the connection defined in section 2.2.3, DE 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 in the future, the very nature of renewable generation and its rapid advancements will likely require that the exact data exchange requirements 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 DE 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, the Facilities Interconnection Requirements (FIR) will not specify the exact revision numbers for these documents. The customer and DE 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 follows data requirements from a legacy data standard, while the new interconnection being added to the station follows 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 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

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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 to the widely varied 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.

#### 3.2.1.1 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.

#### 3.2.1.2 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, the next to the second, etc. The customer is to identify which protection relay or input/output (I/O) device this status is sourced from.

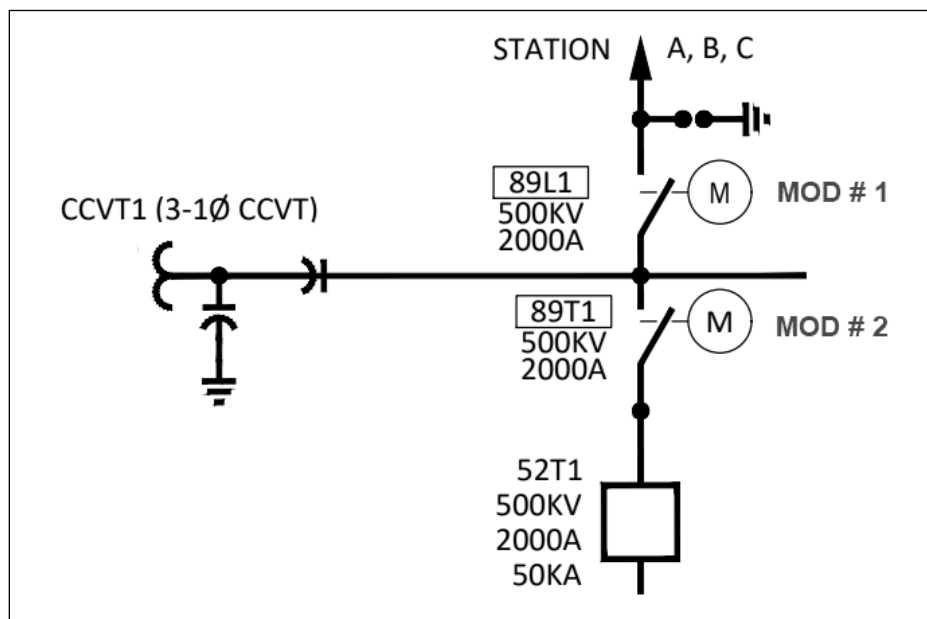



Figure 2. Example Series Motor-operated Disconnect Configuration

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### 3.2.1.3 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.

### 3.2.1.4 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 the line lockout indication from each relay. The communications failure alarm for each line relay is to be provided.

### 3.2.1.5 Site Control Meters


Generation facilities will have a variety of different metering configurations. To ensure complete information is supplied to DE, 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 2 high-side control meters, up to 4 low-side control meters per GSU with up to 3 GSUs, and up to 2 circuit sub-meters per feeder circuit, up to 12 circuits. These meters are referred to as the power quality meters (PQM) 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.

### 3.2.1.6 PPC/Park Pilot

The customer is to provide the operating state of the Real Power (MW) Proportional Integral Derivative (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).

### 3.2.1.7 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, which is measured in watts per square meter (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 square meter (solar only). The customer is to provide the humidity measurements from every humidity sensor at every met station, which are 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

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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 to report data issues to the future O&M provider.

### 3.2.1.8 Photovoltaic Array (Solar Version Only)


All inverters referenced in this section are associated with the photovoltaic (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, 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 an 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 the maximum real power setpoint that the PPC is allowed to write to each inverter when controlling the point of interconnection (POI) MW output. This value is typically the nameplate rating of the inverter but can sometimes be artificially curtailed to ensure the site’s 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 an 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 to report 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.

### 3.2.1.9 Wind Turbines (Wind Version Only)

The customer is to provide the turbine’s 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. It can also 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 that the site’s maximum power capacity is not exceeded at the POI. The customer is to provide the maximum lead/lag allowed reactive power

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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 to report 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.


### 3.2.1.10 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 (expressed as a percentage), BESS maximum charge MW, and 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 providing 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 to report 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 the 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 that the site’s 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.

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### 3.2.2 Generator to DEV: “Control Data” Data Exchange Requirements

The data exchange requirements for the control data link are specific to the PPCs. An important note for this section is that this only defines 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 DEV. 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.

#### 3.2.2.1 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.

#### 3.2.2.2 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. A corresponding point in the DNP analog input map 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.

#### 3.2.2.3 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.

#### 3.2.2.4 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

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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.

#### 3.2.2.5 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. DEV is to mark up this documentation and provide the customer with the data points based on the site configuration.

#### 3.2.3.1 Transmission Breakers


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

#### 3.2.3.2 Transmission Line

Line Differential protection is required between the two facilities. DEV 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 with the differential fiber channel failure alarm, the abnormal potential alarm, and the line lockout indication from each relay. The communications failure alarm for each line relay is to be provided to the customer.

#### 3.2.3.3 Islanding

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

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### 3.2.3.4 POI Metering

There is a primary and backup revenue meter at the POI within the GI substation. These meters are referred to as the Revenue Quality Meters (RQM) in some contexts, as these are the revenue meters of record for PJM. These meters provide the “net” metering for the generation facility. DEV is to provide the customer with 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 with 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 its own precisely timed freeze, read, and time differential calculation to determine the total counts for the previous hour. DEV is to provide the communications failure alarms for each POI revenue meter.


### 3.2.3.5 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 a DNP analog input point. 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.

## 4.0 CUSTOMER SITE DOCUMENTATION REQUIREMENTS TO DEV

DEV 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 DEV 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 shows 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 (D-Curve) for the facility. 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 meteorological 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 meteorological station.
- For solar, the per-inverter watt/VAR maximum capability. If the inverters are skid-based, identify the maximum capability per skid watt/VAR. If the number of inverters varies per skid, this will need to be

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broken down on a skid-by-skid basis. Identify if the inverters’ maximum VAR capability differs when used for nighttime VAR support and the actual maximum VAR capability.

- For wind, the maximum capability per turbine watt/VAR. Identify which turbines (if any) support no-load reactive power support and the maximum var capability when the turbine is 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.

## 5.0 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 DEV SOC. The setpoint is issued through the GI Substation via the GI RTAC Generator to the 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 owner. 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 for the generation facility across DEV to the 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 the generator has fallen outside of the allowed voltage band. There has been a “status change” in the AVR functionality of the site, according to requirement R3 of the North American Electric Reliability Corporation’s (NERC) VAR-002 standard [3]. This alarm also marks the start of a 30-minute timer. If the voltage continues to stay out of the 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 transmission owner (the SOC) and transmission operator (PJM) when this 30-minute threshold is crossed as per the NERC VAR-002 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 the real power setpoint controls. This setpoint will electronically transmit the unit-requested real power output from

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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).

## 6.0 CONSTRUCTION PROJECT MILESTONES AND DEV SOC SCADA REQUIREMENTS

Certain SCADA requirements must be met before the DEV SOC will allow the generation facility to backfeed, reach the first sync, and start generating power for the grid. There are also SCADA tests that must be performed once the site is fully commissioned prior to substantial completion (detailed in the following sections). 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 Backfeed


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

- The SOC must have visibility of the generation facility’s 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 Coupling Capacitor Voltage Transformer (CCVT) at the 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 DEV 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 generator operator must acknowledge their voltage schedule in PJM’s eDart application. Additionally, 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 modeled the generation units as per the site D-Curve and nameplate characteristics into the EMS system and state-estimator. The EMS modeling team requires the documentation as specified in Section 4 to complete this task.

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- 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 so 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 the 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.
- For 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.


### 7.0 REFERENCES

1. "Facility Interconnection Requirements," Dominion Energy Virginia—Electric Transmission, most recent version.
2. *PJM Manual 14D: Generator Operational Requirements*.
3. *VAR-002 Generator Operation for Maintaining Network Voltage Schedules*, North American Electric Reliability Corporation.

### 8.0 REVISION HISTORY

**Table 1. Revision History**

Revision Date	Revision #	Description	Revised By	Effective Date
03/10/2023	0.0	Document Creation	Daniel Camp	4/1/2023
07/24/2024	1.0	See Details for Revision 1.0 Below	Jason Lettieri	09/01/2024
03/11/2025	2.0	See Details for Revision 2.0	Kristen Custer	04/01/2025
9/10/2025	3.0	See Details for Revision 3.0	Kristen Custer	10/01/2025

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**Details for Revision 1.0**


- Revision contributors include Daniel Ridenour, Micah Till, Aaron Winter, Colleen Wallace, Keith Graham, Mark Gill, Mohsen Mahoor, Peter Nedwick, and Quanta Technology.
- Removed signature page and consolidated on FIR cover page.
- Reviewed for content and consistency.

**Details for Revision 2.0**

- Revision contributors include the following: Kristen Custer, Keith Graham, and Quanta Technology.
- Document formatting (fonts, margins, etc.) updated to improve readability. Changed the main font from Arial to Aptos.
- Updated Abbreviations and Acronyms.
- Acronyms moved to the front of the document to align with the main FIR document.
- Grammatical modifications including capitalization, spelling, punctuation, and consistency.

**Details for Revision 3.0**


- Revision contributors include the following: Kristen Custer, Keith Graham, and Quanta Technology.
- Editorial updates only: grammatical corrections, spelling, punctuation, and capitalization.
- Consistency improvements in terminology (e.g., acronyms, singular/plural use).
- Minor style/clarity adjustments in section wording and table references.

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# Attachment 6


## Generation Interconnection Substation Technical Requirements

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## Abbreviations and Acronyms


Term	Definition
<b>ANSI</b>	American National Standards Institute
<b>BES</b>	Bulk Electric System
<b>BIL</b>	Basic Impulse Level
<b>CL</b>	Centerline
<b>D/B/A</b>	Doing Business As
<b>DE</b>	Dominion Electric
<b>DEV</b>	Dominion Electric Virginia
<b>DEV-ET</b>	Dominion Electric Virginia—Electric Transmission
<b>EHV</b>	Extra-high Voltage
<b>ERAG</b>	Eastern Interconnection Reliability Assessment Group
<b>FERC</b>	Federal Energy Regulatory Commission
<b>FIR</b>	Facility Interconnection Requirements
<b>GSU</b>	Generator Step-up Transformer
<b>HV</b>	High Voltage
<b>IA</b>	Interconnection Agreement
<b>IEC</b>	International Electrotechnical Commission
<b>IEEE</b>	Institute of Electrical and Electronics Engineers
<b>MCOV</b>	Maximum Continuous Operating Voltage
<b>MOV</b>	Metal Oxide Varistor
<b>NERC</b>	North American Electric Reliability Corporation
<b>NESC</b>	National Electric Safety Code
<b>P&amp;C</b>	Protection and Control
<b>POI</b>	Point of Interconnection
<b>QC</b>	Quality Control
<b>RRO</b>	Regional Reliability Organization
<b>RTU</b>	Remote Terminal Unit
<b>SERC</b>	SERC Reliability Corporation
<b>TO</b>	Transmission Operator

## Definitions


Term	Definition
<b>Basic Impulse Level</b>	A BIL is a reference impulse insulation strength expressed in terms of the crest value of the withstand voltage of a standard full impulse voltage wave.
<b>Clearance: Minimum Phase-to-Ground</b>	The shortest metal-to-metal distance between an energized part(s) and the adjacent grounded part(s).
<b>Clearance: Minimum Phase-to-Phase</b>	The shortest metal-to-metal distance between any energized part(s), where the parts are different phases or different voltage magnitudes.

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Term	Definition
<b>Extra-high Voltage</b>	Transmission lines rated 765 kV, 500 kV, and 345 kV and transformers with secondary voltages at or above 345 kV are considered EHV facilities and are referred to as EHV facilities in this document. These facilities are part of the BES.
<b>Engineering Service Provider</b>	Refers to contractors and suppliers who provide DEV-ET’s engineering services.
<b>Facility</b>	A set of electrical equipment that operates as a single electric system element (e.g., a line, a generator, a shunt compensator, a transformer).
<b>Facility Construction Agreement</b>	Refers to the agreement that details the costs, construction schedule, and responsibilities of each party during the construction of the Interconnection Facilities.
<b>Facility-owned Interconnection Facilities</b>	Refers to facilities or portions of facilities owned by the Facility Owner, from the Facility up to the Interconnection Point, which, in conjunction with the Facilities, are necessary to affect the transfer of power between the Facility and the Transmission System.
<b>Facility Owner</b>	Refers to the organization that is the actual owner of the facilities being connected to the Transmission System.
<b>Flicker</b>	Refers to low-frequency voltage fluctuations observed through changes in intensity or color of illumination. Flicker is measured using an International Electrotechnical Commission (IEC) flicker meter.
<b>Federal Energy Regulatory Commission</b>	A commission that regulates the interstate transmission of electricity, natural gas, oil, hydropower projects, and natural gas terminals.
<b>Generation</b>	Refers to the electrical capacity and energy produced at the Facility.
<b>Generator Connection</b>	New or materially modified (affiliated or non-affiliated) connection for a generating facility, typically connected directly to the DEV-ET transmission system, to participate in a wholesale market.
<b>Generator Capability Curve</b>	Refers to the production of megawatts and megavars throughout its output range, which the generating unit manufacturer typically provides.
<b>Good Utility Practice</b>	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.
<b>Ground Grid</b>	A system of ground rods and interconnected bare cables buried in the earth to limit touch and step voltages to acceptable levels and provide a common ground for electrical devices and metallic structures.
<b>Harmonics</b>	Refers to the content of a signal whose frequency is an integer multiple of the actual system frequency (e.g., the main frequency produced by the generators or, for the United States, 60 cycles per second).

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Term	Definition
<b>High Voltage</b>	Transmission lines typically rated 230 kV, 161 kV, and 138 kV, and transformers with secondary voltages above 100 kV but below 345 kV are considered HV facilities and are referred to as HV facilities in this document. These facilities are part of the BES.
<b>Interconnection Agreement</b>	Refers to the agreement that documents the physical interconnection between the Facility Owners and DEV-ET and defines the continued responsibilities
<b>Interconnection Facilities</b>	Refers to the Change of Ownership, at which point the Facility-owned Interconnection Facilities are connected to the DEV-ET Interconnection Facilities.
<b>Maximum Continuous Operating Voltage</b>	The maximum power frequency voltage can be applied to a metal oxide arrester continuously.
<b>Metal Oxide Varistor</b>	A surge arrester utilizing valve elements fabricated from a metal oxide material.
<b>Rigid Conductor</b>	Wire or tubular bus that does not sag or move appreciably due to load, temperature, ice, or wind loading.
<b>Surge Arrester</b>	A protective device for limiting surge voltage on equipment by diverting surge current and returning the device to its original status. It is capable of repeating these functions as specified.

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## 1.0 INTRODUCTION

### 1.1 Purpose

This document establishes minimum standard requirements for Interconnect Customers to design and build safe, efficient, and reliable substations for Virginia Electric and Power Company, doing business as (d/b/a) Dominion Energy Virginia (DEV). Accordingly, DEV Electric Transmission (DEV-ET) will be responsible for designing and building the transmission line that will connect with the Interconnect Customer substation. Therefore, from now on, throughout this document, DEV will be referred to as DEV-ET.

For the application of this document, essential requirements for building DEV-ET substations are outlined. These include general requirements from Civil/Site, Physical, Electrical, and Protection and Control. Once an Interconnection Agreement (IA) is finalized, the Interconnect Customer shall use the provided DEV-ET specifications, standard designs, construction documents, and drawings. Since this document is intended to focus on the layout and design of the substation, Interconnection Customers shall refer to the DEV’s Facility Interconnection Requirements document<sup>1</sup>, PJM Tariffs, and governing documents<sup>2</sup> for an essential understanding of the generation interconnection Option-to-Build process and procedures.

Interconnection Customers and DEV-ET shall also adhere to the North American Electric Reliability Corporation (NERC) Standard FAC-001,<sup>3</sup> which requires Transmission Owners (TO) and applicable Generator Owners to provide Facility Interconnection Requirements (FIR) documentation to prospective entities seeking to connect to DEV-ET systems.

Refer to Section 5.0 References for more information.

### 1.2 Intended Audience

The intended audiences for this Technical Requirements for Generation Interconnect Substations document include:

- Interconnection Customers’ respective engineering, construction, and operations staff and consultants.
- TOs’ respective engineering, construction staff, contractors<sup>4</sup>, and consultants.

### 1.3 Abbreviations and Definitions


Abbreviations and definitions are listed in this attachment’s front matter.

<sup>1</sup> DEV-ET’s FIR: facility-connection-requirements1.ashx (pjm.com).

<sup>2</sup> PJM Governing Documents: <https://pjm.com/library/governing-documents>.

<sup>3</sup> NERC FAC-001: <https://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-001-3.pdf>.

<sup>4</sup> DEV-ET refers to Contractors as Engineering Service Providers (these terms are interchangeable).

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## 1.4 Roles and Responsibilities

### 1.4.1 Interconnect Customer

Interconnect Customers exercising an option to build a substation facility are responsible for, but not limited to, the following:

- Quality Control (QC) walkthrough and review of the provided list of points of contact for each approved contractor, standard drawings, and specifications.
- Adherence to DEV-ET’s environmental and permitting requirements.
- Build and design DEV-ET’s substations as outlined in the IA.
- Training of substation systems.
- Procurement of DEV-ET’s approved equipment and materials or all option-to-build substations.
- Use of DEV-ET’s list of approved contractors.
- Compliance with non-disclosure agreements, NERC requirements, and DEV-ET Cyber Security systems.
- Inspection, tests, and energizing of DEV-ET’s substations.
- Adhering to any applicable federal, state, and local codes along with any applicable NERC, Reliability First, or PJM requirements.
- Deeding the Facility to DEV-ET after the completed work is approved.


### 1.4.2 Transmission Owner

The TO (DEV-ET) is responsible for, but is not limited to, the following during an Interconnection project:

- Providing the Generation Interconnect Substation Specifications Portfolio outlining a list of points of contact for each approved contractor, standard drawings, and specifications at the time of IA.
- QC walkthrough and review of the provided list of points of contact for each contractor, standard drawings, and specifications.
- Review and comment on design work performed by the Interconnect Customer.
- Review of Equipment Acceptance Test.
- Calibration of Remote Terminal Units (RTU) and Relay Settings.
- Review of approved contractors.
- Review of construction.
- Assistance with Permitting, Land Rights, and Authorizations.
- Quality Assurance review to ensure standards and specification accuracy.
- Maintenance of the Facility after work is approved and the substation is deeded to DEV-ET.

## 1.5 Scope

An Interconnect Customer exercising the option to build a DEV-ET substation or connect a generation facility to a substation must guarantee that all work is safe to the public, reliable, and of high quality, ensuring DEV-ET’s effortless maintenance of the Facility after taking ownership. Therefore, it is pertinent that the

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Interconnect Customer adhere to the outlined DEV-ET’s Substation design and build requirements. Further, they must follow the NERC Reliability Standards<sup>5</sup>.

The requirements outlined in this document are basic and do not include specifications, detailed documentation, and drawings. These details will be provided in a portfolio during an IA between the Interconnect Customer and DEV-ET. Further, during a Generation Interconnection project, the Interconnect Customer shall comply with all requirements outlined in the portfolio and the IA.

This document references DEV-ET’s FIR<sup>6</sup>, which provides a broader scope of Interconnection requirements. In addition, transmission Interconnection documents are available on the DEV-ET website<sup>7</sup> for additional guidance.

Although planning is out of scope for this document, the DEV-ET FIR guides the planning phase of a typical project. DEV-ET safeguards the transmission planning standards of NERC and those of the SERC Reliability Corporation (SERC), one of the six regional reliability organizations (RRO) of NERC.

## **2.0 REQUIREMENTS**

### **2.1 Design Drawing Requirements**

When an Interconnect Customer designs and builds a DEV-ET substation, drawings shall emulate the DEV-ET engineering drawing package required to construct the substation. Upon completion of the substation, a set of as-built construction drawings and documentation is to be provided to DEV-ET. The As-built drawing set shall contain the following:

- Electrical.
- Protection and Control (P&C).
- Structural.
- Civil drawings.
- Vendor documentation.

Nomenclature and numbering shall emulate DEV-ET standards such as those outlined in the Uniform Numbering System.

Be aware that once an IA is finalized, DEV-ET specifications, drawing templates, and other required documents will be provided upon request.

### **2.2 Voltage Level and MW and MVAR Capacity or Demand at the Point of Interconnection**

The Interconnection Customer shall refer to DEV-ET’s FIR, Section 2.2.


### **2.3 Breaker Duty and Surge Protection**

The Interconnection Customer shall refer to DEV-ET’s FIR, Section 2.3.

<sup>5</sup> NERC Reliability Standards: <https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx>.

<sup>6</sup> 1214 FAC-001 Facility Interconnection Requirements: [facility-connection-requirements1.ashx](https://www.ferc.gov/energy-projects/facility-connection-requirements1.ashx) (pjm.com).

<sup>7</sup> Dominion Energy Virginia website: <https://www.dominionenergy.com/virginia>.

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**2.4 System Protection Coordination**

The Interconnection Customer is responsible for the accurate design and testing of the protection system that ensures that all work is safe to the public, is reliable, and protects its equipment against disturbances on DEV-ET’s system and minimizes the effects of disturbances from its facilities on DEV-ET’s equipment and Transmission System. Therefore, the Interconnection Customer shall adhere to DEV-ET’s FIR, Section 2.4.

**2.5 Metering and Telecommunications**

The Interconnect Customer shall adhere to DEV-ET’s FIR, Section 2.5.

**2.6 Grounding and Safety Issues**

The Interconnect Customer shall adhere DEV-ET’s FIR, Section 2.6.

**2.7 Insulations and Insulation Coordination**

The Interconnect Customer shall adhere to DEV-ET’s FIR, Section 2.7.

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

The Interconnect Customer shall adhere to DEV-ET’s FIR, Section 2.8.

**2.9 Power Quality Impacts Flicker**

The Interconnect Customer shall adhere to DEV-ET’s FIR, Section 2.9.

**2.10 Equipment Ratings**

The Interconnect Customer shall adhere DEV-ET’s FIR, Section 2.10.

**2.11 Synchronizing of Facilities**

The Interconnect Customer shall adhere DEV-ET’s FIR, Section 2.11.

**2.12 Maintenance Coordination**

The Interconnect Customer shall adhere to DEV-ET’s FIR, Section 2.11.3.

**2.13 Operational Issues (Abnormal Frequency and Voltages)**


The Interconnect Customer shall adhere to DEV-ET’s FIR, Section 2.11.4.

**2.14 Load-shed Program as Required by PJM**

The Interconnect Customer shall adhere to DEV-ET’s FIR, Section 2.11.5.

**2.15 Communications and Procedures during Normal and Emergency Operating Conditions**

The Interconnect Customer shall adhere DEV-ET’s FIR, Section 2.11.6.

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## 2.16 Site Grading

The installation of a DEV-ET standard substation begins with the proper site selection. Accordingly, many factors, such as site accessibility, drainage, erosion protection, and the amount of necessary site preparation, must be considered. Also, the necessary permits to work on a site must be acquired before starting construction. During the design and build of a DEV-ET substation, the Interconnect Customer shall adhere to the Substation Civil-Site Grading Specification and related standards documentation provided by DEV-ET. Standard documentation shall be provided to the Interconnect Customer at the time of an IA.

## 2.17 Fencing

Substation fences shall be installed at the beginning of construction. This applies particularly to construction projects involving trenches and structures that unauthorized persons might climb.

Specifications cover perimeter fence specifications based on the station's functionality, where it is being installed. A perimeter fence constructed of steel fabric is the preferred physical barrier for substation sites. In some cases, the county, city, or residence may require a decorative fence.

## 2.18 Foundations

Substation foundation design primarily depends on the in-place density and strength/strain characteristics of the soil (supporting the wide range of ground line reactions) that are associated with structures and equipment. The heterogeneous characteristics of soils or their localized variability make the foundation design much less exact than the analysis associated with structural design or some facets of electrical design.

There are various types of substation structures, having a wide variety of ground line reactions. The foundations used to support these structures and equipment depend upon the soil information, constructability concerns, and preferences of the design engineer. Some common foundations used in substations are:

- Drilled piers (or drilled shafts).
- Spread footings.
- Slabs on grade.
- Single-application “special” foundation (e.g., piles, rock anchors, and/or direct embedment).

## 2.19 Structures


Substation structures fix above-grade components and electrical equipment such as conductors (rigid and strain bus), switches, surge arresters, insulators, and other equipment to specified locations. The structures are designed to safely support equipment and electrical components through applicable mechanical loads from wind, ice, line tensions, earthquakes, construction and maintenance, and other specified or unusual service conditions.

## 2.20 Bus Design

The design and installation of rigid buses are common in all DEV-ET substations. Bus designs shall adhere to minimum electrical and structural properties as governed by the conditions below.

Applicable bus design conditions include the following:

- Minimum ampacity requirements.

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- Maximum anticipated short-circuit currents.
- Maximum operating voltage.
- Maximum anticipated wind speeds.
- Maximum expected icing conditions combined with wind.
- The altitude of the station.
- Basic substation layout.

## 2.21 Lighting

Yard lighting shall be provided in substations to deter criminal activity and flood the general area. Yard lighting is not intended to furnish sufficient lighting to permit all forms of night work. For this purpose, portable spots and floodlights shall be used. The number of permanent lights provided depends on the size of the substation.

## 2.22 DEV-ET Interface Documents

Two essential interface documents include the Substation/Transmission Engineering Interface and the Substation/Distribution interface.

### 2.22.1 Interconnect Customer Substation/DEV-ET Transmission Engineering Interface

This section summarizes the responsibilities of and the communication interface between Transmission Line Engineering and Substation Engineering for the design of transmission line structures inside substations. Transmission Line Engineering is responsible for designing, specifying, and procuring the transmission line structures located within the substation fence. Transmission Line Engineering is also responsible for designing and procuring the foundation materials.


Substation Engineering is responsible for specifying and procuring the line disconnect switches and necessary grounding material for those structures. A transmission line structure inside a substation is defined as any structure supporting a flexible conductor using strain insulators. Included in this definition are the following:

- Tubular backbone structures.
- Tubular line structures.
- Steel “A” structures.
- Strain-bus structures.
- Static pole structures.

Transmission Line Engineering shall develop the line phasing diagram with the required approvals and forward it to Substation Engineering for review. Substation Engineering shall develop the one-line diagrams for the substation construction and obtain the required approvals. Transmission Line Engineering will review the drawings for any transmission work, including phase positions, line switches, and termination positions.

### 2.22.2 Interconnect Customer Substation/DEV-ET Distribution Interface

Where applicable, this section summarizes the responsibilities of and the communication interface between Distribution Design and Substation Engineering. This established exchange of information is essential for the design of distribution getaways and other interface points between substations and distribution lines. Substation Engineering will provide Distribution Planning with a copy of the General Arrangement Plan. Planning will provide Substation Engineering with a copy of the distribution line construction plan so that the poles and underground circuits can be properly located inside the substation. The circuit getaway circuit shall

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be overhead construction whenever possible. When an underground getaway is required, a spare conduit must be included with the terminal structure foundation. A spare conduit will allow more efficient recovery of lost circuits due to cable failures. As required, Distribution Planning must specify the need for dual terminal structures. Disconnects or other means of isolation may be required on distribution circuits to facilitate maintenance.

### 2.23 Grounding

In designing a substation grounding system, the primary objective is to provide safe conditions for equipment and personnel operating in and about the substation during both normal and abnormal conditions.

Grounding of power systems is achieved by embedding electrical conductors into the earth and electrically connecting these conductors to the neutral of the power system. In this way, a low impedance is provided between the power system neutral and the vast conducting soil, which guarantees that the voltage of the neutral, concerning earth, will be low under all conditions.

Grounding is necessary for several reasons, including:

- Ensuring the correct operation of electrical devices.
- Providing safety during normal or fault conditions.
- Stabilizing the voltage during transient conditions.
- Dissipating lightning strokes.

### 2.24 Electrical Connections

Connections in substations are designed for extremely high reliability. In support of high reliability, connector design is influenced by certain factors. These factors are creep (cold flow), surface oxide, corrosion, and thermal effects.


Types of connections include:

- Bolted.
- Compression.
- Welded.
- Exothermic.

### 2.25 Station Shielding

The Institute of Electrical and Electronics Engineers (IEEE) *Guide for Direct Lightning Stroke Shielding of Substations* presents four significant methods of protecting substations from lightning strikes: fixed angles, empirical curves, the computer program SBSHLD, and the rolling sphere method. SBSHLD and the rolling sphere method are generally the more conservative methods, and both are based on the electrogeometric model. Both depend greatly on the voltage withstand capability of the substation. The methods of fixed angles and empirical curves, however, depend only on distances between masts or shield wires and the objects they protect.

All four methods require similar resources to protect higher voltage substations, but the methods vary significantly in protecting lower voltage levels (230 kV or less). The DEV-ET policy provides the most significant protection to higher voltage substations. They are a more critical part of the power system—both SBSHLD and

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the rolling sphere method attempt to provide equal protection to all substations. Because of the reduced voltage withstand capability associated with low voltage substations, using these methods results in a greater concentration of masts and wires per area unit at these locations. These methods soon become impractical and excessive. Since the voltage withstand capability is not a factor in either the fixed angle or empirical curve methods, they inherently provide the best protection at higher voltages.

Although fixed angles and empirical curves have similarities, they differ in the size of the protection zone. The method of empirical curves protects more significant areas at lower elevations. We believe this is a more accurate representation because the information presented in each curve results from actual lightning strikes and has been compiled for over 50 years. The fixed-angle method is a straight-line approximation of the empirical method.

As much as possible, substation equipment will be protected from lightning by either shield wires or lightning masts. However, it is impossible to provide 100% protection to all equipment because of the randomness and uncertainty associated with lightning strikes. For this reason, equipment is protected within a certain failure rate or percentage at which the protection system fails.

For design purposes, it is recommended that the engineer use a failure rate of 0.1% whenever possible. However, a failure rate of greater than 0.1% may be used if the recommended method is not feasible or if the need for protection is not significant enough to warrant the cost; this is left to the engineer’s discretion.

Once the height (d) of the device to be protected is known, the curves can be used to determine the maximum allowable distances between the device and the static wire(s) or mast(s) protecting it. The empirical shielding curves provide information about the vertical and horizontal locations necessary for adequate protection. The vertical distance (h) is measured from the ground, while the horizontal distance (x) is measured from the protected object.

Figure 1 through Figure 5 give the empirical curves for 5 different shielding situations at a 0.1% and a 1% failure rate. The lower curve is more restrictive in each case and indicates a 0.1% failure rate.

## 2.26 Electric Clearances

Maintaining electrical clearance around energized conductors and parts is one of the most critical aspects of substation design. “Clearance” or distance from a live electrical part is necessary for the safety of personnel working in the area and for the reliable operation of the electrical substation equipment.


## 2.27 Codes and Standards

The National Electric Safety Code (NESC), 2007 revision, was used to develop the clearance tables. NESC provides safety rules for the design of electrical supply equipment and associated work practices.

IEEE documents C37.32 and C1427 were used where applicable.

## 2.28 Personnel Clearances

NESC Rule 124.A.1 states that “guards shall be provided around all live parts operating above 300 V...unless their location gives sufficient horizontal or vertical clearance.”

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## 2.29 Roadway Clearances

Bus conductors that span substation roadways must be high enough to allow the tallest utility truck, crane, or apparatus to be driven or transported underneath it and maintain phase-to-ground clearance from live parts. The tallest apparatus to be transported in the substation is the power transformer.

## 2.30 Equipment Disassembly and Movement

Consideration must be given to providing adequate clearances for disassembling and moving equipment. The primary example is removing the bushings from a transformer and moving them out of the substation. The manufacturer’s outline drawing for the electrical equipment shall be used to determine the clearance needed. The minimum electrical clearances in Table 8’s Column A must be adhered to during the disassembly and moving process to provide adequate clearances.

### 2.30.1 Clearances at a Perimeter Fence

This section clarifies design requirements for the location of substation fences concerning overhead conductors or live parts inside a substation. The intent of the electrical clearance safety zones, noted in the body of this interpretation, is listed below.

**Table 1. Electrical Clearance Safety Zones Interpretation**

Safety Type	Description
<b>Public Safety</b>	Reduce possible hazards to anyone outside the substation fence.
<b>Minimum Approach Distance</b>	Ensure proper working clearance from the fence to overhead conductors and live parts inside the substation. The NESC will assign electrical clearance requirements per voltage class.

### 2.30.2 Tables and Figures

Electrical clearance figures and tables are outlined in Table 4.

## 2.31 Equipment

Surge arresters are required to protect power system equipment from overvoltages. Arresters shall be of a MOV design for substation applications.


Refer to Table 9 for more information.

## 3.0 APPROVED MAJOR SUBSTATION EQUIPMENT

Interconnect Customers exercising an option-to-build substation facility as a part of an interconnection project must procure equipment and materials from DEV-ET’s list of approved contractors.

## 4.0 APPROVED CONTRACTORS

All option-to-build work, defined in Tariff Section 3.2.3, must be performed by a contractor approved by DEV-ET. A DEV-ET representative will provide a list of approved contractors and a point of contact(s) for each approved contractor, along with a portfolio of standard drawings and specifications at the time of the IA.

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Contractors currently under contract and working on DEV-ET property will not be available for the Interconnect Customer option-to-build work.

Interconnect Customer right-to-build Contractor crews shall be approved by DEV-ET and will not be allowed to work more than 40 hours per week without DEV-ET review and approval. Further, additional criteria (such as insurance, contract provisions, etc.) shall be required for review before the approval of the Interconnection Customer option-to-build work on DEV-ET's distribution system.

A review of a detailed schedule from the Interconnect Customer using DEV-ET-approved contractors for the specified upgrades shall be required to determine the reasonableness of the proposed schedule.

Be aware that once the Interconnection Customer has entered into an interconnection agreement, the Interconnection Customer shall contact DEV-ET to review the most up-to-date list.

## 5.0 REFERENCES

1. Dominion Energy Facility Interconnection Requirements, Standard Requirements #: FAC-001 R1 and R3
2. Dominion Energy Substation Engineering Manual
3. Dominion Technical Standards: <https://www.pjm.com/planning/design-engineering/to-tech-standards/private-dominion>
4. IEEE Std 998 – 1996, IEEE Guide for Direct Stroke Lightning Stroke Shielding of Substations
5. Manual 14B- PJM Region Transmission Planning Process
6. NERC Planning Standard TPL-001
7. NERC PRC Standards 12 - 17
8. NERC Reliability Standard NUC-001
9. North American Electric Corporation website at [www.nerc.com](http://www.nerc.com)
10. Nuclear Switchyard Interface Agreement CO-AGREE-000-IAL
11. Nuclear Switchyard Interface Agreement System Analysis Protocol CO-AGREE-000-IAL-4
12. PJM Manual 39- Nuclear Plant Interface Coordination
13. Transmission System Performance SERC Supplement


### 5.1 Regarding Interconnection Agreement Documentation and References

Once the Interconnection Customer has entered into an interconnection agreement with DEV-ET, a portfolio containing detailed documentation and drawings will be provided for option-to-build generation interconnection work.

## 6.0 REVISION HISTORY

**Table 2. Revision History**

Revision Date	Revision #	Description	Revised By	Effective Date
06/21/2022	0	See Details for Revision 1.0 below	Theresa Robinson	06/21/2022
06/22/2022	1	See Details for Revision 2.0 below	Theresa Robinson	06/22/2022
07/21/2022	2	See Details for Revision 3.0 below	Theresa Robinson	07/21/2022
10/21/2022	3	See Details for Revision 4.0 below	Theresa Robinson	10/21/2022

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Revision Date	Revision #	Description	Revised By	Effective Date
10/31/2022	4	See Details for Revision 5.0 below	Theresa Robinson	10/31/2022
11/28/2022	5	See Details for Revision 6.0 below	Theresa Robinson	-
11/29/2022	6	See Details for Revision 7.0 below	Theresa Robinson	-
12/12/2022	7	See Details for Revision 8.0 below	Theresa Robinson	12/12/2022
07/06/2023	8	See Details for Revision 9.0 below	Theresa Robinson	07/06/2023
08/21/2023	9	See Details for Revision 10.0 below	Theresa Robinson	08/21/2023
12/20/2023	10	See Details for Revision 11.0 below	Theresa Robinson	12/20/2023
06/11/2024	11	See Details for Revision 1.0 below	ET Planning	09/01/2024
03/11/2025	12	See Details for Revision 12.0 below	ET Planning	04/01/2025
9/10/2025	13	See Details for Revision 12.0 below	ET Planning	10/01/2025

#### Details for Version 0.0

- Contributors include Theresa Robinson, Justin Harsh, Gustavo Leal, Patrick J Loepker, Chase Chambers, William “Chase” Bland, Joel Trivitte, and Tania Jones.
- Initial draft.

#### Details for Revision 1.0


- Contributors include Keith Graham.
- Cover page: Updated document ID and title.

#### Details for Revision 2.0

- Contributors include Keith Graham.
- Cover page: Updated document ID and title to reflect the title used in the kick-off email.

#### Details for Revision 3.0

- Contributors include Keith Graham, Justin Harsh, Wilson Velazquez, Philip VanSant, David Logan, Suinna Duncan, Theresa Robinson, and Gustavo Leal.
- Cover page: Updated date and added.
- Table of figures: Added new figures.
- Table of tables: Added new section.
- Throughout document: Replaced “should” with “shall.” Corrected grammatical and formatting issues.
- Section 1.1: Added the Interconnect Customer “shall use the provided DEV-ET standard designs.”
- Section 2.1: Added a new section to address Design Drawing Requirements.
- Section 2.4: Added reference to the Substation Civil Site-grading Specification and related standards documentation provided by DEV-ET.
- Section 2.2: Reiterated Interconnect Customers “shall use DEV-ET standard designs.”
- Appendix G: Added Power Engineers to the list of approved contractors and added Civil-Site approved contractors.

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#### Details for Revision 4.0

- Contributors include Nickolaus N Dillon.
- Cover page: Updated date and added the final edits to complete the document.
- Appendix F: Added the suppliers of 115 kV transformers.

#### Details for Revision 5.0

- Contributors include Theresa Robinson.
- Cover page: Changed date before creating PDF.
- All pages: Removed line numbers from the document.

#### Details for Revision 6.0

- Contributors include Phillip VanSant.
- Page 14: Refined equation with Word tool and added Equation label.
- Page 15: Added Table 1 and label.
- All appendices: Modified all tables and table references.
- Table of tables: Updated table sequence.
- Signature page: Removed until further notice.

#### Details for Revision 7.0


- Contributors include Phillip VanSant.
- Sections 2.2–2.15: Removed content and referenced Facility Interconnection Requirements, Standard/Requirement # FAC-001 R1 and R3, Section 4.1.3–4.1.16.

#### Details for Revision 8.0

- Contributors include Justin Bell.
- Section 1.2: Replaced the 2021 version of FIR with the 2023 version.
- Section 1.5: Replaced the 2021 version of FIR with the 2023 version.
- Appendix G: Removed individual names from all contractor lists in lieu of establishing one Dominion Energy point of contact that provides detailed information upon signing an IA.

#### Details for Revision 9.0

- Contributors include Keith Graham and Sarah Craig.
- Section 1.4.1: Added the following text:
  - Quality Control walkthrough and review of the provided list of points of contact for each approved contractor, standard drawings, and specifications.
- Section 1.4.2: Added the following verbiage:
  - Providing the Generation Interconnect Substation Specifications Portfolio outlining a list of points of contact for each approved contractor, standard drawings, and specifications at the time of IA.
  - Quality Control walkthrough and review of the provided list of points of contact for each approved contractor, standard drawings, and specifications.
- Section 4: Added the following verbiage:

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- A DEV-ET representative will provide a list of points of contact(s) for each approved contractor, along with a portfolio of standard drawings and specifications at the time of the IA.

**Details for Revision 10.0**

- Contributors include Keith Graham and Sarah Craig.
- Appendix G: DEV-ET Approved List of Contractors (Table 11) based on Rev#25.30.23 doc.

**Details for Revision 11.0**

- Revision contributors include Theresa Robinson, Pamela Torrez, and Quanta Technology.
- Replaced cover page with title page consistent with other attachments.
- Removed signature page and consolidated on FIR cover page.
- Removed Appendix F: DEV-ET Approved Materials and Equipment Suppliers (to be maintained outside of this document).
- Removed Appendix G: DEV-ET Approved List of Contractors (to be maintained outside of this document).
- Updated references.

**Details for Revision 12.0**

- Revision contributors include the following: Kristen Custer, Keith Graham, and Quanta Technology.
- Document formatting (fonts, margins, etc.) updated to improve readability. Changed the main font from Arial to Aptos.
- Updated Abbreviations and Acronyms.
- Acronyms moved to the front of the document to align with the main FIR document.
- Grammatical modifications including capitalization, spelling, punctuation, and consistency.

**Details for Revision 13.0**

- Revision contributors include Kristen Custer, Keith Graham, Nancy Ashberry and Quanta Technology.
- Editorial updates only: grammatical corrections, spelling, punctuation, and capitalization.
- Consistency fixes in terminology (e.g., singular/plural forms, defined terms, common noun capitalization).
- Minor style changes for clarity in tables, headings, and section wording.

## APPENDIX A: STATION INSULATION LEVELS

Table 3 provides standard equipment and basic insulation levels. Be aware that “other” equipment includes switches, insulators, breakers, etc.

**Table 3. Station Insulation Levels**

System Voltage (kV)	Transformer BIL	Other BIL
<b>500</b>	1,550	1,800
	1,425 *	
	1,300 *	
<b>230</b>	750	900
	650 *	
<b>138</b>	550	650
	450 *	
<b>115</b>	450	550
	350 *	
<b>69</b>	350	350
<b>46</b>	250	250
<b>34.5</b>	200	200 and 150
<b>23</b>	150	150
<b>13.2</b>	95	110
<b>12.5</b>	95	110
<b>11.5</b>	95	110
<b>6.0</b>	95	95
<b>4.16</b>	75	75
<b>2.4</b>	60	60

\* Insulation levels are old standards, but many of these transformers are on the system.



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**APPENDIX B: SUBSTATION SHIELDING**

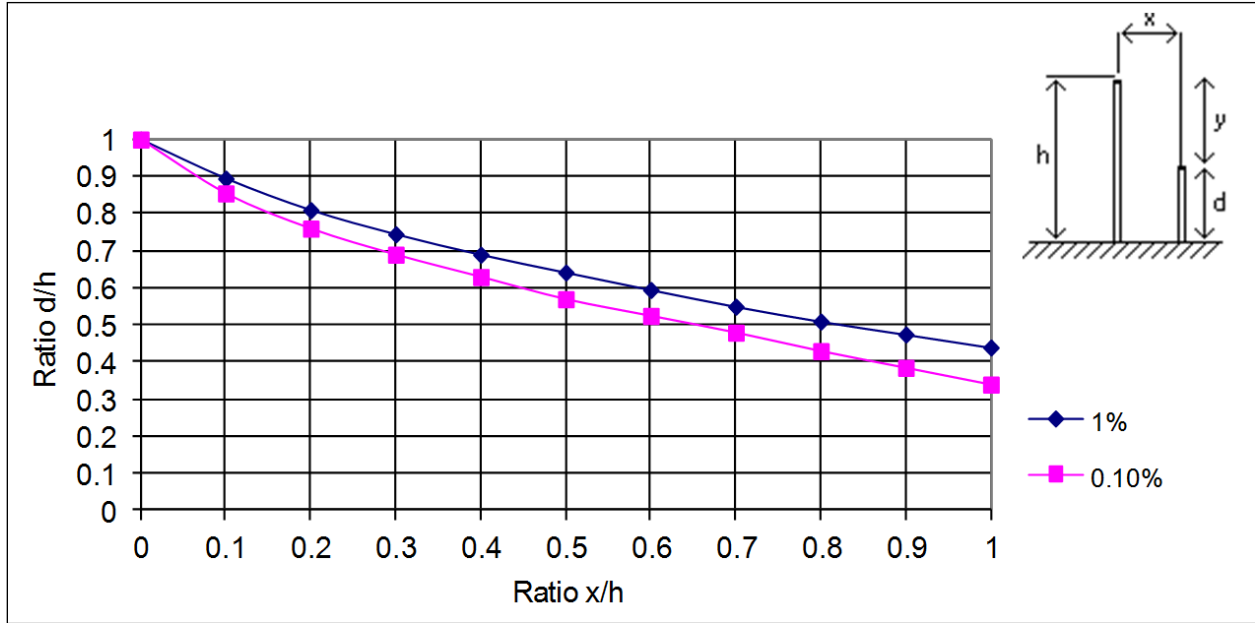


Figure 1. Protection of an Exposed Object by a Single Lightning Mast

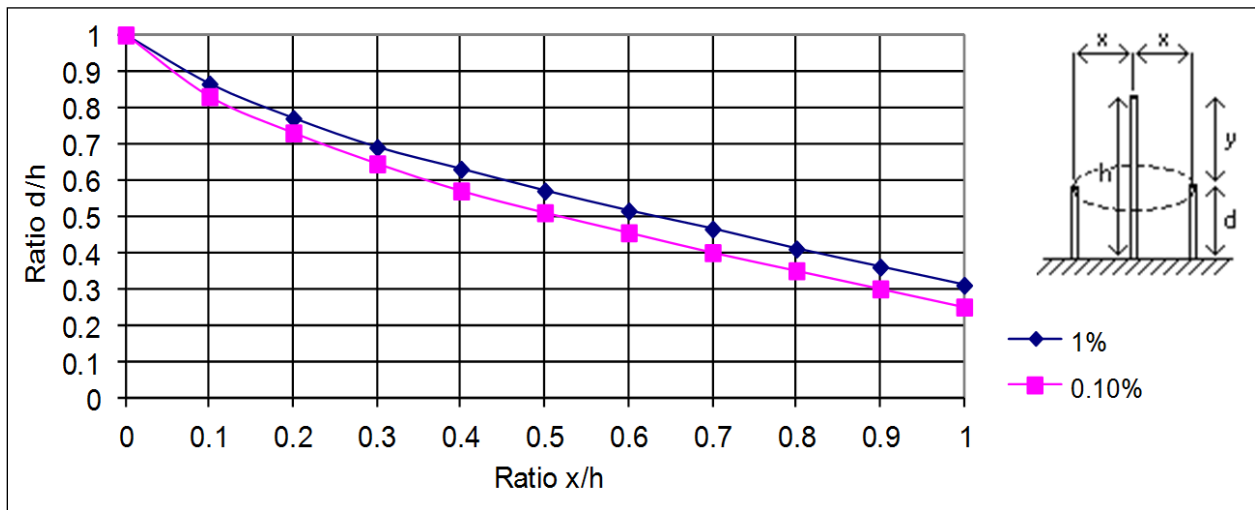


Figure 2. Protection of Ring of Exposed Objects by a Single Lightning Mast



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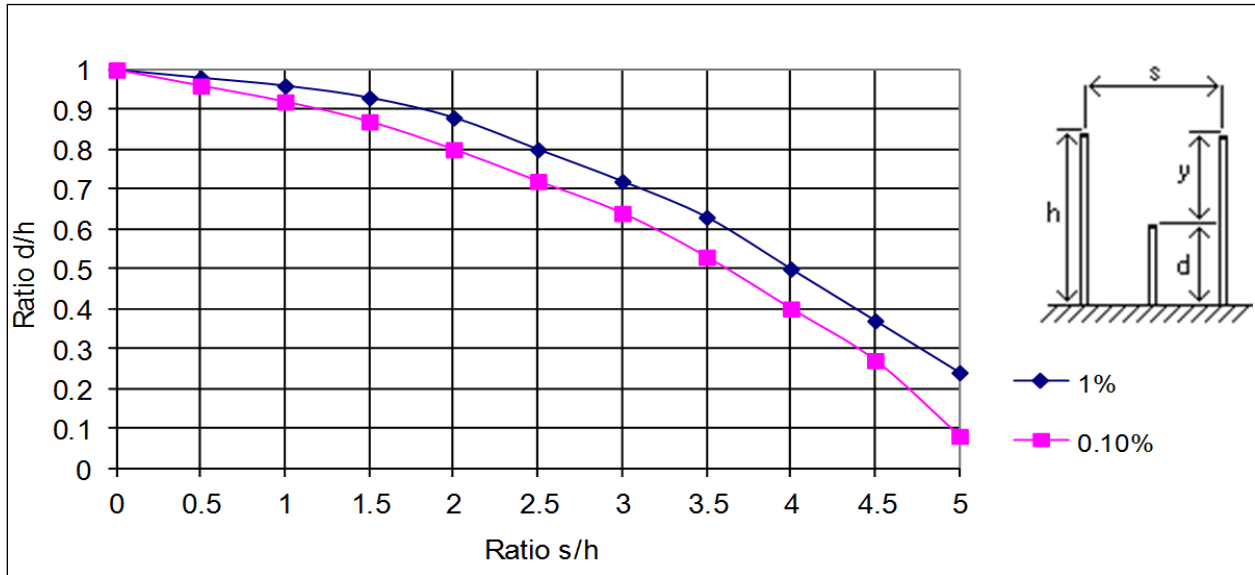


Figure 3. Protection of an Exposed Object by Two Lightning Masts

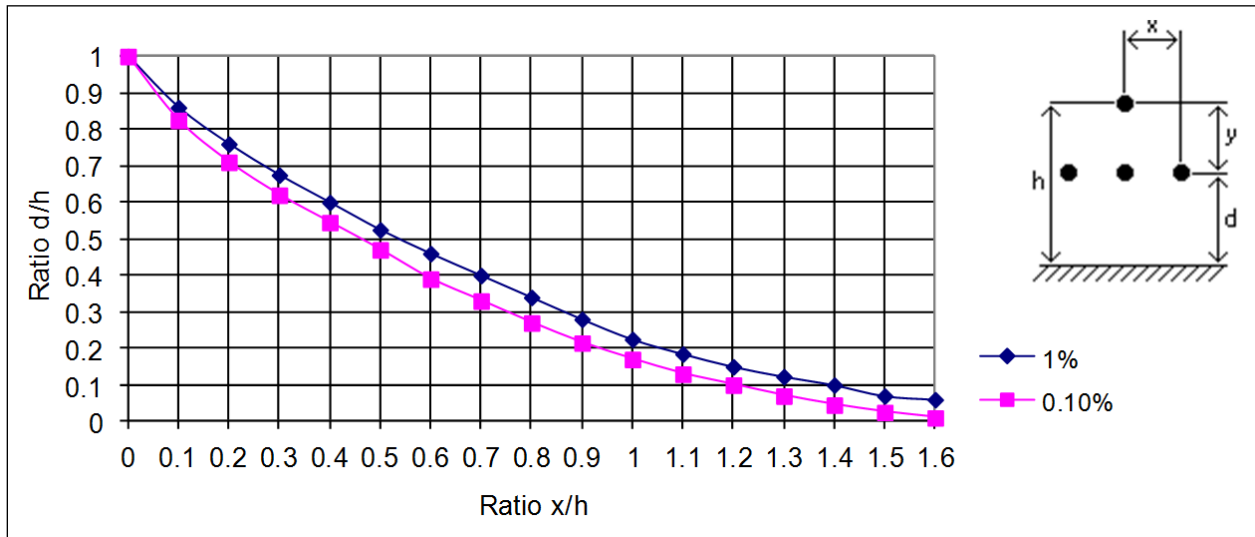


Figure 4. Protection of Exposed Horizontal Conductors by Single Wire



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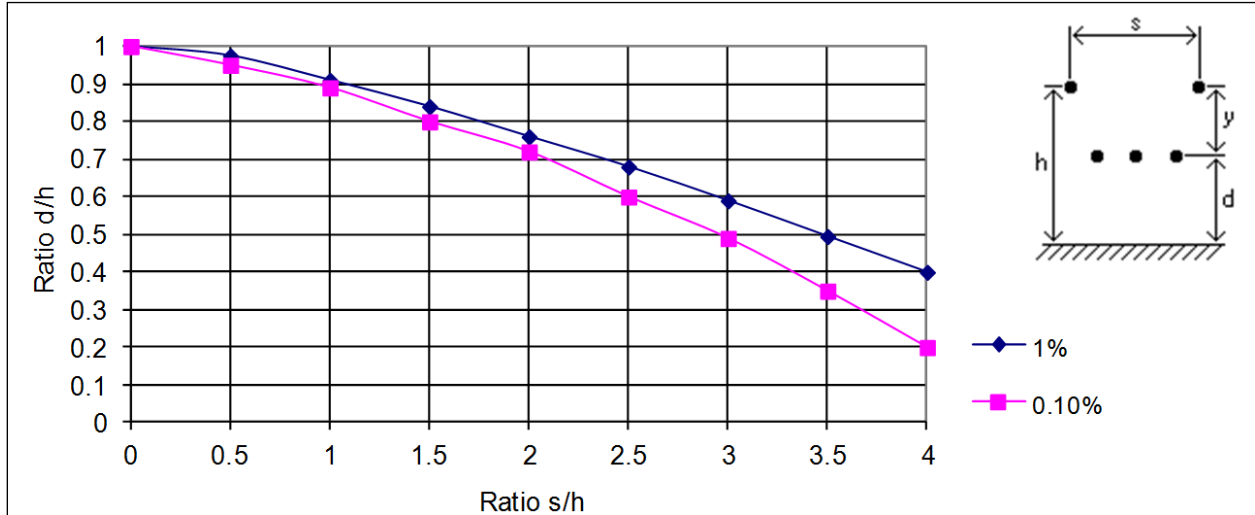
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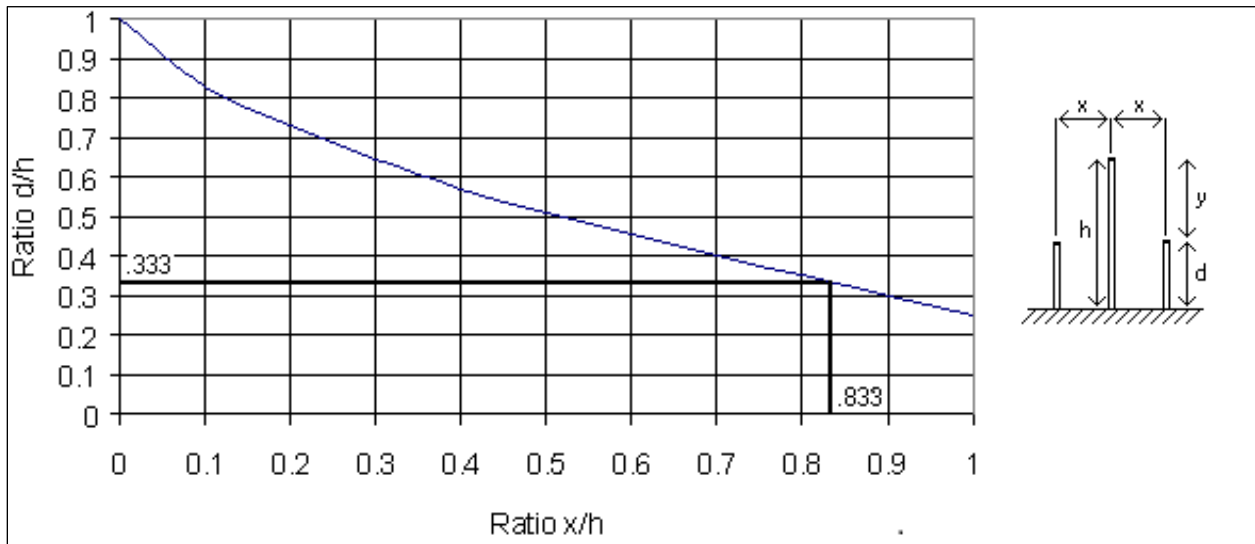


**Figure 5. Protection of Exposed Horizontal Conductors by Two Shield Wires**


For an example of how to use these curves, from Figure 2 (using 0.1% exposure), it can be seen that a mast at the height of 60 feet can protect all objects up to 20 feet high within a radius of up to 50 feet.

$$h = 60, \quad d = 20, \quad \frac{d}{h} = \frac{20}{60} = .333 \xrightarrow{\text{therefore}} \frac{x}{h} = .833 \quad x = \frac{x}{h}(h) = .833(60) \cong 50 \text{ feet}$$

If the objects in that same circle were at a height of 25 feet (instead of 20 feet), a mast of approximately 68 feet would be required to provide the same failure rate of 0.1%. (If  $d = 25$  and  $x = 50$ , then  $h$  can be determined through a trial and error method.)



**Figure 6. Example 1**

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A similar example with shielding wires can be found in Figure 4. A static wire at a height of 65 feet can protect a 25-foot tall object at a horizontal distance of up to 40 feet. (See Figure 7.)

$$h = 65, \quad d = 25, \quad \frac{d}{h} = \frac{25}{65} \cong .385 \xrightarrow{\text{therefore}} \frac{x}{h} = .62 \quad x = \frac{x}{h}(h) = .62(65) \cong 40.3 \text{ feet}$$

For a wire at a height of only 50 feet to protect the same object (with the same failure rate), the horizontal distance between the two must be no greater than 23 feet.

$$h = 50, \quad d = 25, \quad \frac{d}{h} = \frac{25}{50} = .5 \xrightarrow{\text{therefore}} \frac{x}{h} = .46 \quad x = \frac{x}{h}(h) = .46(50) \cong 23 \text{ feet}$$

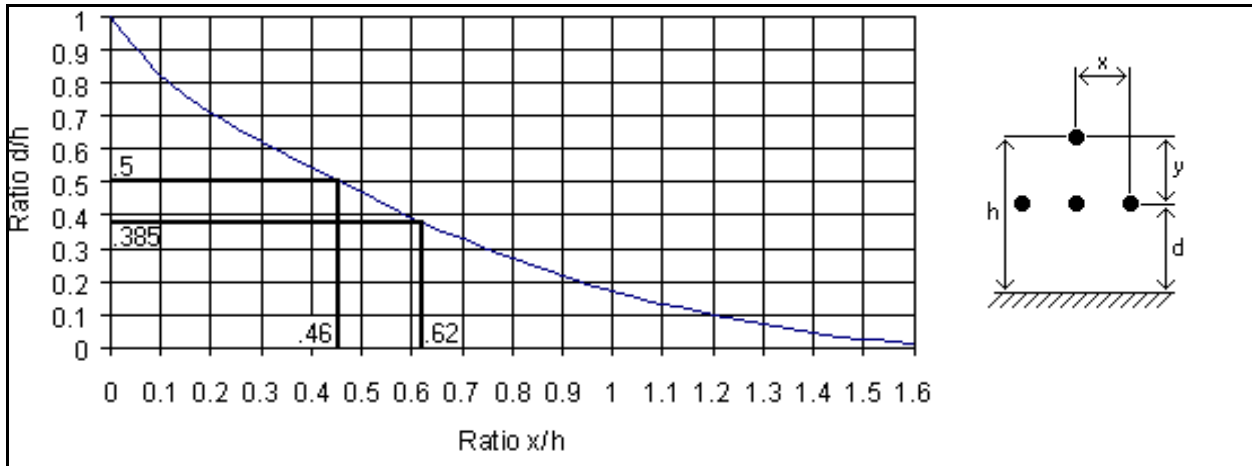


Figure 7. Example 2

The most used method of protection against lightning strokes is that of the single shield wire. This information is displayed graphically in Figures 4 and 5 below. These graphs can be used to find the relationship between the height of an object and the allowable distance between that object and the shield wire protecting it. For example, Figure 4 shows that a shield wire at 65 feet can protect an object 20 feet high at a distance of approximately 47 feet.



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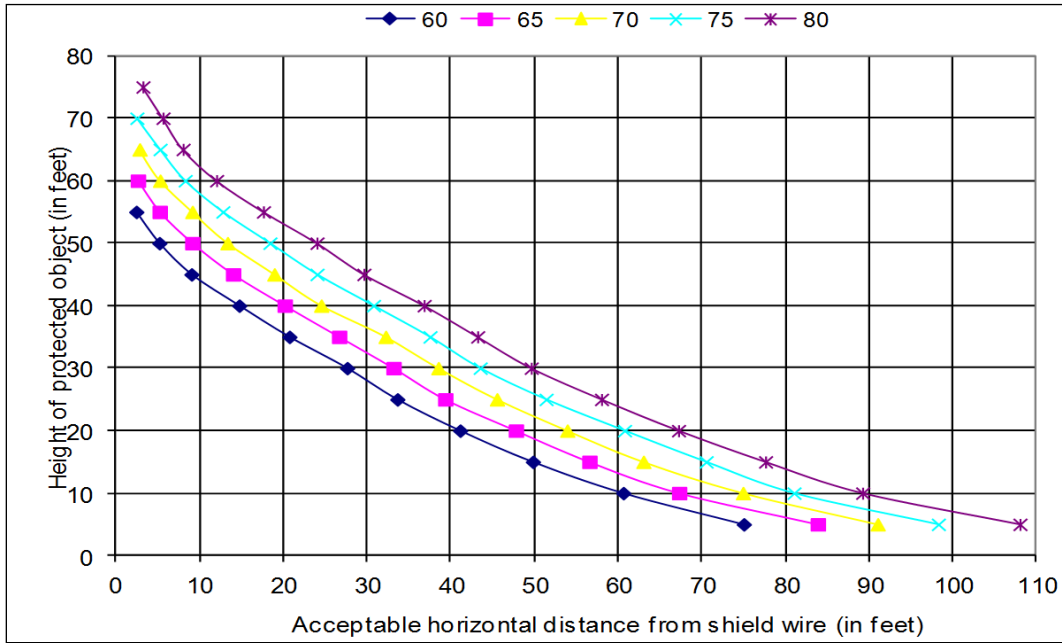
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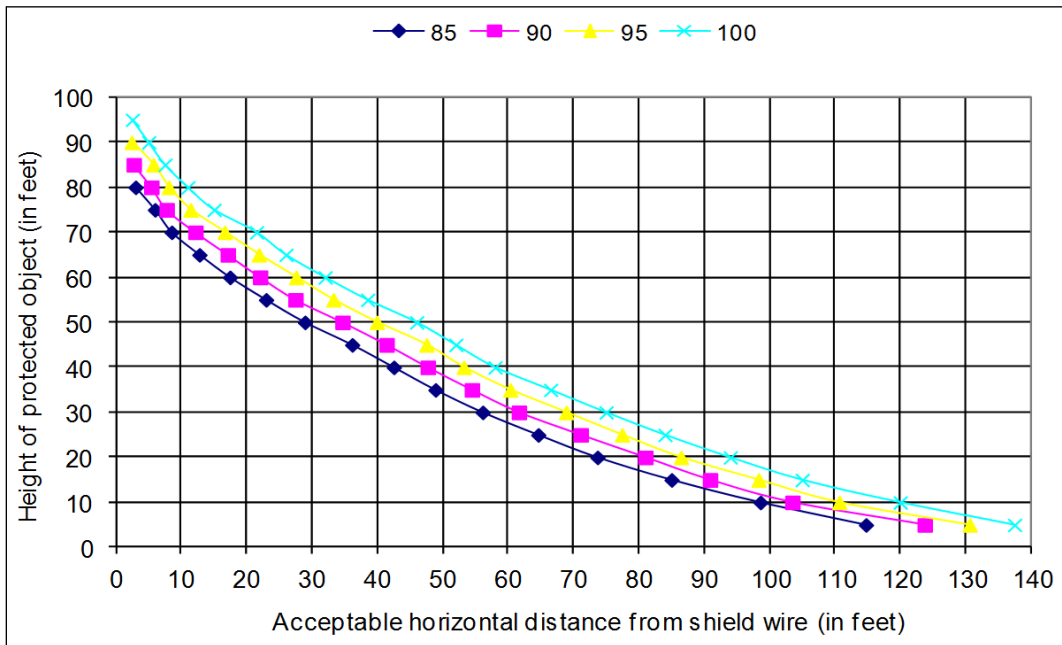
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**Figure 8. Protection Provided by Shield Wires at Different Heights**



**Figure 9. Protection Provided by Shield Wires at Different Heights**

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The method of empirical curves for protection against lightning strokes has been used and modified for decades, yet it continues to be an effective method of protection, and it remains highly accepted in the industry. Other, more complex lightning protection methods have been developed, but none have been proven to be any more effective than the simple shielding of equipment provided by static wires or lightning masts.

## APPENDIX C: ELECTRICAL CLEARANCES FIGURES AND TABLES

For Table 4, minimum physical clearance is 1'-0", regardless of voltage class.

**Table 4. Phase-to-ground Clearances at Elevations Below 3,300'**

P-P  kV	BIL	(a)	(b)	(c)	(d)	(e)
		P-G	Vertical to	Vertical to	Horizontal to	Horizontal to
		Rigid Parts	Ungrounded	Live Parts	Ungrounded	Live Parts
		(Min) <sup>8</sup>	(Min) <sup>9</sup>	(Min) <sup>10</sup>	(Min) <sup>11</sup>	(Min) <sup>12</sup>
7.5	95	0'-4"	8'-6"	8'-10"	3'-0"	3'-4"
15	110	0'-6"	8'-6"	9'-0"	3'-0"	3'-6"
23	150	0'-9"	8'-6"	9'-3"	3'-0"	3'-9"
34	200	1'-0"	8'-6"	9'-6"	3'-0"	4'-0"
46	250	1'-4"	8'-6"	9'-10"	3'-0"	4'-4"
69	350	1'-11"	8'-6"	10'-5"	3'-0"	4'-11"
115	550	3'-1"	8'-6"	11'-7"	3'-0"	6'-1"
138	550	3'-1"	8'-6"	11'-7"	3'-0"	6'-1"
138	650	3'-8"	8'-6"	12'-2"	3'-0"	6'-8"
230	900	5'-3"	8'-6"	13'-9"	3'-0"	8'-3"
345	1,050	7'-0"	8'-6"	15'-6"	3'-0"	10'-0"
345	1,300	8'-8"	8'-6"	17'-2"	3'-0"	11'-8"
500	1,550	10'-4"	8'-6"	18'-10"	3'-0"	13'-4"
500	1,800	12'-0"	8'-6"	20'-6"	3'-0"	15'-0"

For Table 5, the minimum physical clearance is 1'-0", regardless of voltage class.


<sup>8</sup> NESC Table 124-1, Column 4 (Part A < 345 kV > Part B)

<sup>9</sup> NESC Table 124-1, Column 2 minus Column 4 (124-1 Part A < 345 kV > Part B)

<sup>10</sup> NESC Table 124-1, Column 2 (Part A < 345 kV > Part B)

<sup>11</sup> Column (e) - Column (a)

<sup>12</sup> NESC Table 124-1, Column 3

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**Table 5. Phase-to-phase Clearances at Switch**

P-P	BIL	(a)*	(b)*	(c)*	(d)*	(e)*	(f)
		Vertical Break Disc	Vertical Break Disc	Horizontal Break Disc	Horizontal Break Disc	Air Interr. Switch	P-P Metal to Metal
kV		(Typ)	(Min) <sup>13</sup>	(Typ)	(Min) <sup>15</sup>	(Min) <sup>14</sup>	(Min) <sup>15</sup>
7.5	95		1'-6"		2'-6"	3'-0"	0'-8"
15	110	3'-0"/5'-0"	2'-0"	5'-0"	2'-6"	3'-0"	0'-9"
23	150	3'-0"/5'-0"	2'-6"	5'-0"	3'-0"	4'-0"	1'-0"
34	200	3'-0"/5'-0"	3'-0"	5'-0"	4'-0"	5'-0"	1'-4"
46	250		4'-0"		5'-0"	6'-0"	1'-9"
69	350		5'-0"		6'-0"	7'-0"	2'-5"
115	550	10'-0"	6'-2"	10'-0"	8'-9"	10'-0"	3'-9"
138	550	10'-0"	6'-2"	10'-0"	8'-9"	10'-0"	3'-9"
138	650	10'-0"	6'-11"	10'-0"	9'-6"	12'-0"	4'-6"
230	900	13'-0"	8'-6"	13'-0"	12'-4"	16'-0"	6'-2"
345	1,050	18'-0"	9'-6"	18'-0"	16'-6"	18'-0"	7'-2"
345	1,300	20'-0"	11'-5"	20'-0"	18'-5"	20'-0"	8'-11"
500	1,550	25'-0"	13'-4"	25'-0"	21'-6"	25'-0"	10'-10"
500	1,800	27'-0"	15'-0"	27'-0"	23'-2"	27'-0"	12'-6"

\* CL-to-CL.

For Table 6, the minimum physical clearance is 1'-0", regardless of voltage class.

<sup>13</sup> Minimum P-P clearance for switches rated 7.5 kV through 69 kV per ANSI C37.32 Table #5. For switches rated 115 kV through 500 kV, the clearance was determined by adding the horizontal dimension of the switch measured from centerline to edge of hot part (HP) with the switch in the "open" position + column (f) + a 12" safety factor.

<sup>14</sup> Per ANSI C37.32 Table 5.

<sup>15</sup> Per Table 3 in IEEE 1427, "Electrical Clearance in Air-insulated Substations."

**Table 6. Phase-to-phase Clearances at Bus**

P-P	BIL	(a)*	(b)*	(c)*	(d)*	(e)*	(f)
		Bus	AL <sup>16</sup>	AL Bus <sup>18</sup>	AL Bus <sup>18</sup>	AL Bus (EHV) <sup>181</sup>	P-P Metal <sup>17</sup>
			Angle Bus	Tubular	Tubular	Tubular	to Metal
			3 <sup>1/4</sup> x 3 <sup>1/4</sup> x 1 <sup>1/4</sup>	3 <sup>1/2</sup> IPS	5 IPS	5 and 6 IPS	
kV		(Typ)	(Min)	(Min)	(Min)	(Min)	(Min)
7.5	95		1'-6"	3'-2"			0'-8"
15	110	2'-6"	1'-7"	3'-3"			0'-9"
23	150	2'-6"	1'-10"	3'-6"			1'-0"
34	200	2'-6"	2'-2"	3'-10"			1'-4"
46	250			4'-3"			1'-9"
69	350			4'-11"			2'-5"
115	550	10'-0"		6'-9"	7'-4"		3'-9"
138	550	10'-0"		6'-9"	7'-4"		3'-9"
138	650	10'-0"		7'-6"	8'-1"		4'-6"
230	900	13'-0"		9'-2"	9'-9"		6'-2"
345	1,050	18'-0"				10'-8"	7'-2"
345	1,300	20'-0"				12'-5"	8'-11"
500	1,550	25'-0"				14'-4"	10'-10"
500	1,800	27'-0"				16'-0"	12'-6"

\* CL-to-CL.

<sup>16</sup> CL-to-CL bus clearance was determined by adding the maximum width of bus part (BP) for each kV + Column (f) + Safety Factor (SF). Bus Part maximum dimensions for various bus configurations are as follows:

- 3 1/4 " AL Angle Bus - BP = 3.25"
- 3 1/2 " AL IPS Tubular Bus - BP = 24"
- 5" AL IPS Tubular Non-EHV Bus - BP = 31" (SN 42155968)
- 5" AL IPS Tubular EHV Bus - BP = 30" (SN 42014215)
- 6" AL IPS Tubular EHV Bus – BP=30" (42207982)
- The Safety Factor for buses at 69 kV and below is 3" (SF) at each bus part, or 6" total CL-CL measurement
- The Safety factor for 115 kV and above is 6" SF at each bus part, or 12" total CL-CL measurement

<sup>17</sup> Per Table 3 in IEEE 1427, "Electrical Clearance in Air-insulated Substations."

For Table 7, minimum physical clearance is 1'-0", regardless of voltage class.

**Table 7. Station-class Arresters: Clearance at Arrester Termination**

Arrester		Discharge Voltage	(a)	(b)
		8/20 $\mu$ s Crest	P-G	P-P
Duty	MCOV	20kA Surge <sup>18</sup>	Metal to Metal	Metal to Metal
kV	kV	kV	(Min) <sup>19</sup>	(Min) <sup>20</sup>
3	2.55	8.4	0'-4"	0'-7"
6	5.1	16.8	0'-5"	0'-9"
12	10.2	34	0'-5"	0'-9"
18	15.3	51	0'-7"	0'-11"
30	24.4	81	0'-9"	1'-2"
39	31.5	106	1'-0"	1'-5"
48	39	126	1'-2"	1'-4"
60	48	150	1'-4"	1'-8"
72	57	188	1'-8"	2'-2"
90	74	239	2'-0"	2'-7"
108	88	274	2'-7"	2'-11"
120	98	304	2'-7"	3'-1"
180	144	461	4'-2"	6'-6"
264	212	657	5'-8"	6'-5"
396	318	984	8'-1"	9'-3"

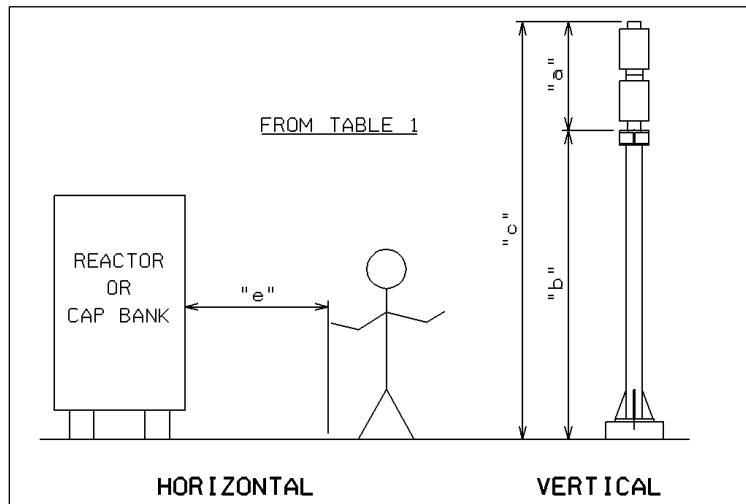
<sup>18</sup> The largest value presently purchased for the listed voltage class.

<sup>19</sup> In accordance with the compared longest P-G distance, provided by the manufacturer or listed in IEEE Std. C62.22-2009.

<sup>20</sup> In accordance with the compared longest P-P distance, provided by the manufacturer or listed in IEEE Std. C62.22-2009.

**Table 8. Electrical Clearances at Substation Fence at Elevations below 3,300'**

P-P kV	(A)	P-G	(B)	(C)	(D)		
	P-G	Minimum	P-G	P-G	Vertical Clearance		
	Public Safety <sup>21</sup>	Approach <sup>22</sup>	Live Parts <sup>23</sup>	Live Parts <sup>24</sup>	Overhead Line to Outside the Substation		
(Live Parts)		(Substation)	(Overhead Line)	H = 12'	H = 15'	H = 20'	
15	10'-2"	2'-2"	7'-2"	8'-0"	20'-0"	23'-0"	28'-0"
23	10'-4"	2'-5"	7'-5"	8'-0"	20'-0"	23'-0"	28'-0"
34	10'-8"	2'-5"	7'-5"	8'-0"	20'-0"	23'-0"	28'-0"
46	10'-11"	2'-7"	7'-7"	8'-3"	20'-3"	23'-3"	28'-3"
69	11'-8"	2'-11"	7'-11"	8'-9"	20'-9"	23'-9"	28'-9"
115	13'-0"	3'-1"	8'-1"	9'-8"	21'-8"	24'-8"	29'-8"
138	13'-9"	3'-7"	8'-8"	10'-2"	22'-2"	25'-2"	30'-2"
230	15'-5"	5'-3"	10'-3"	12'-0"	24'-0"	27'-0"	32'-0"
345	18'-4"	8'-5"	13'-5"	14'-4"	26'-4"	29'-4"	34'-4"
500	19'-10"	11'-1"	16'-1"	17'-5"	29'-5"	32'-5"	37'-5"



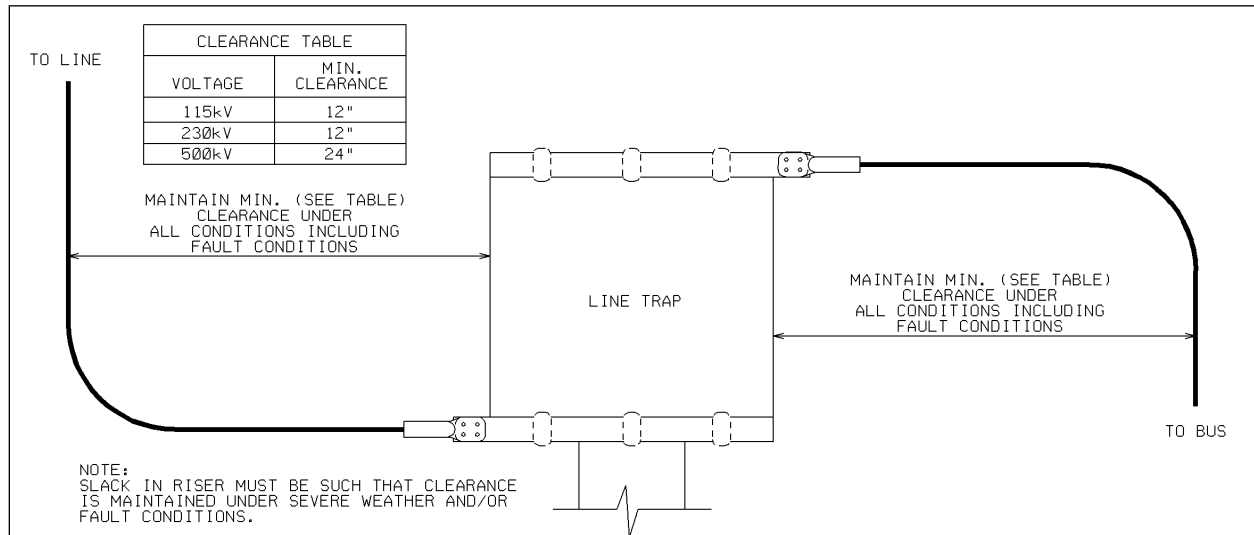
<sup>21</sup> NESC Rule 110: Safety clearance to electric supply station fences.

<sup>22</sup> NESC Rule 441: AC live work minimum approach distance (MAD).

<sup>23</sup> MAD + 5', design value for the safety zone to live parts inside the substation.

<sup>24</sup> NESC Rule 232: Vertical clearance for overhead lines to signs, chimneys, antennas, billboards, etc.

**Figure 10. Personnel and Wavetrapp Clearances**



**Figure 11. Wavetrapp Clearances**



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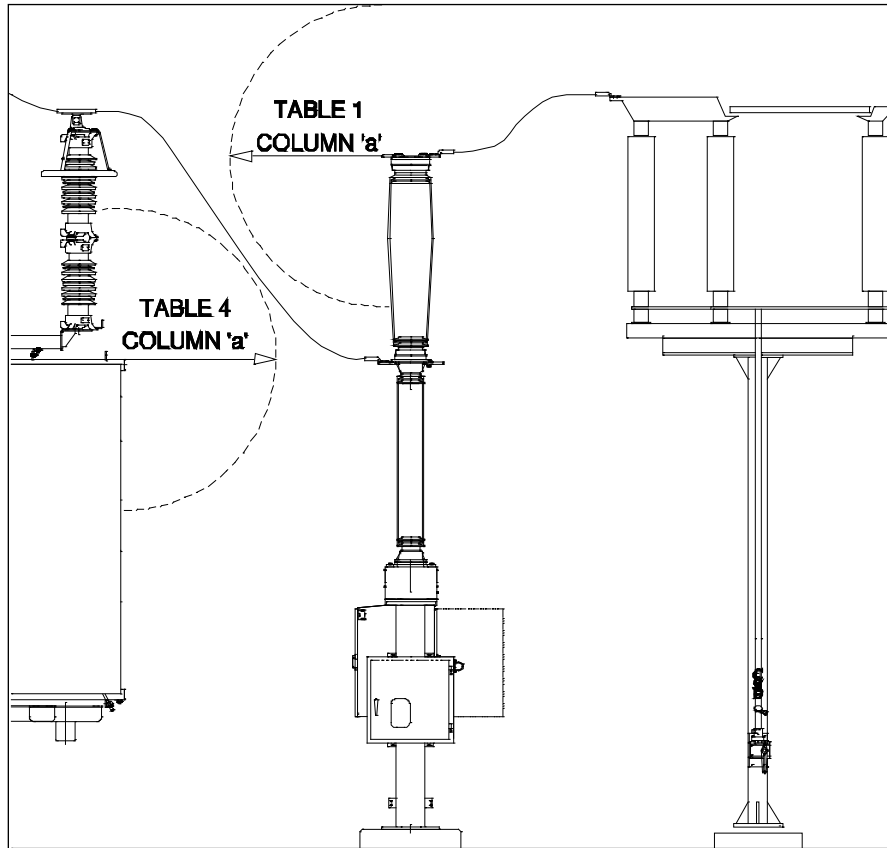
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**Figure 12. Circuit Switcher Clearances**



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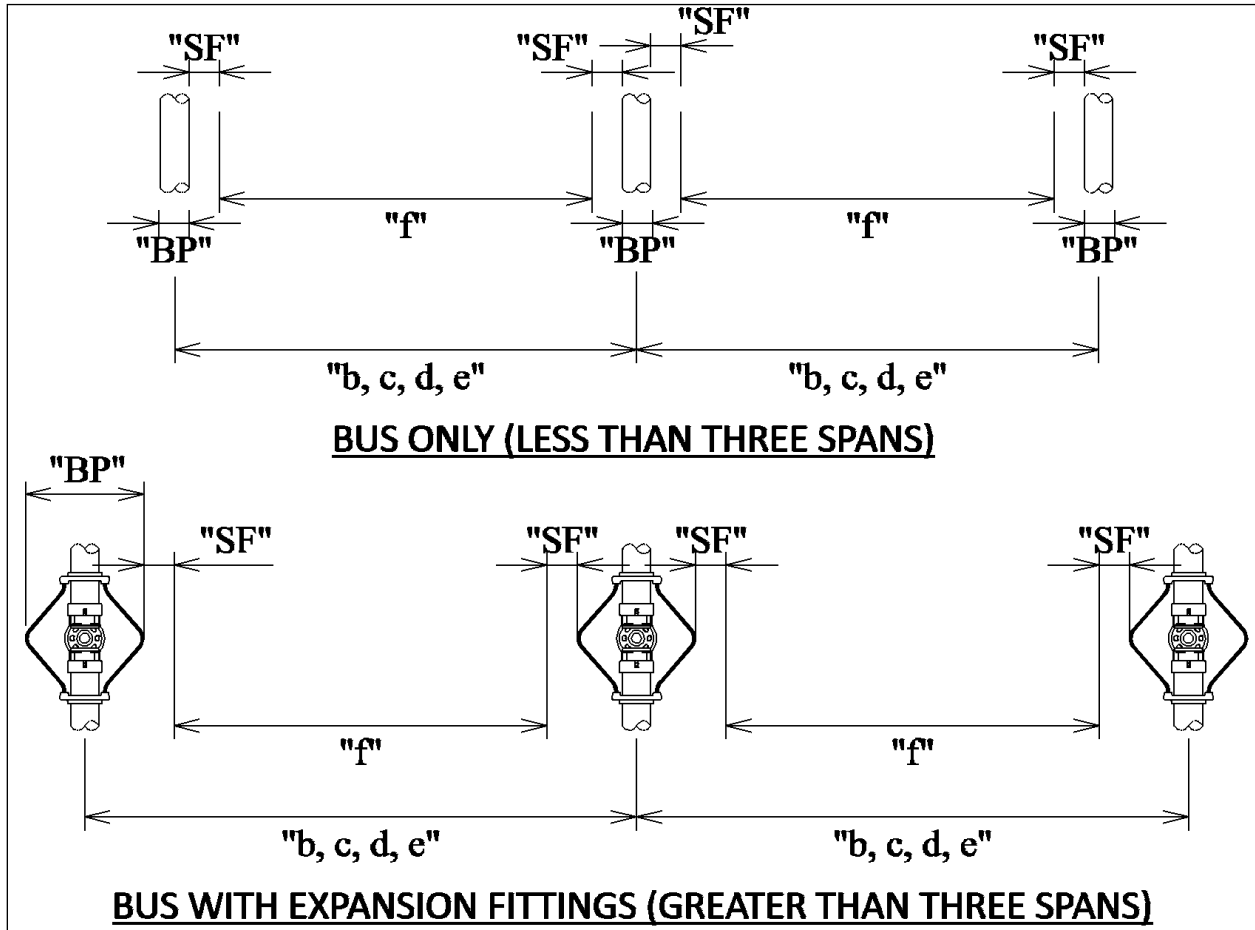


Figure 13. Bus Clearance (Reference Table 6)



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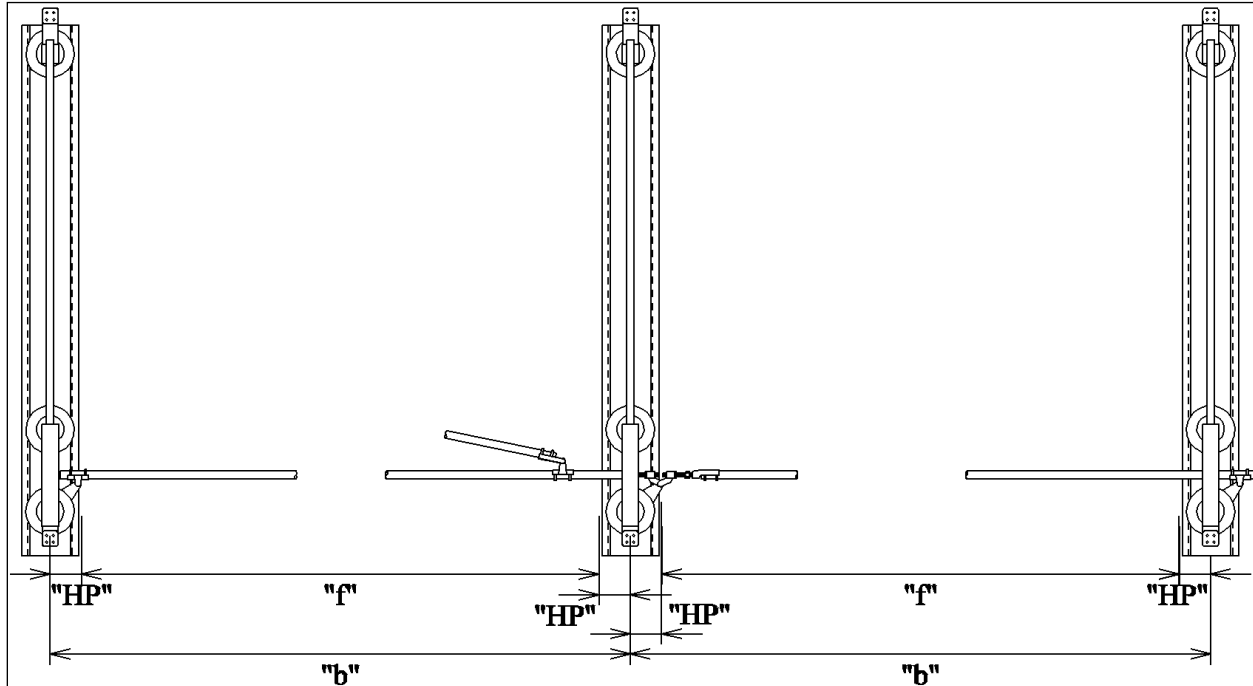


Figure 14. Vertical Break Switch and Center Break Switch Clearances (Reference Table 5)

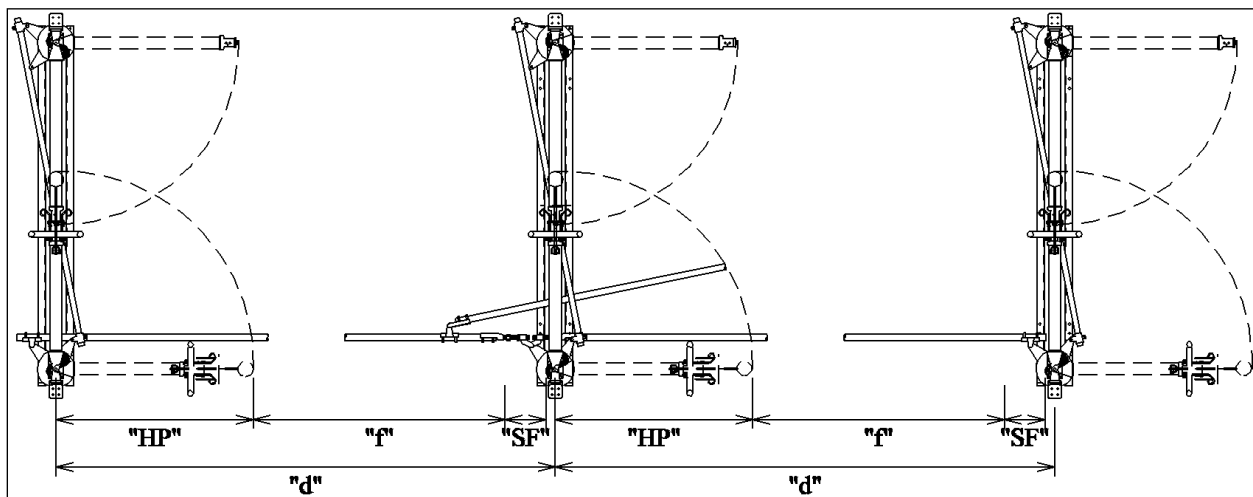


Figure 15. Center Break Switch Clearance (Reference Table 5)



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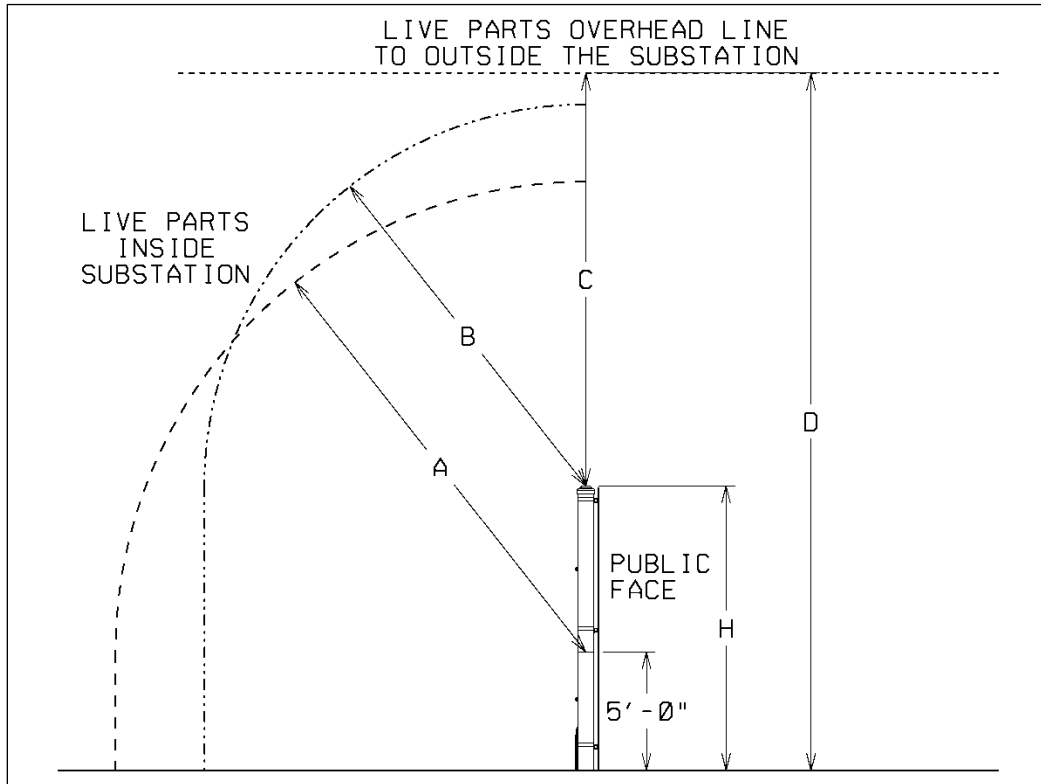
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**Figure 16. Safety Zones at Substation Fence**

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## APPENDIX D: ARRESTERS

Table 9. DEV-approved Substation Arrester Ratings

Line-line Voltage (kV)		Arrester Class*	Duty Cycle Rating (kV)	Approximate MCOV (kV)
Grounded	Ungrounded			
500	-	S	396	318
230	-	S	180	144
138	-	S	108	88
115	-	S	90	74
69	46	S	60	48
-	34.5	S	48	39
46	-	S	39	31.5
34.5	-	S	30	24.4
		DI**	30	24.4
23	13.2	S	18	15.3
		DI**	18	15.3
13.2	-	S	12	10.2
		DI**	12	10.2
12.5	-	S	10	8.4
		DI**	10	8.4
6.0	-	S	6	5.1
4.16	2.4	S	3	2.55
		I**	3	2.55

\* Station Class (S), Intermediate Class (I), Distribution Riser Pole (DI).


\*\* Used on circuit get-a-ways (overhead and underground) and the terminals of intra-substation cable runs.

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# Attachment 7

## Modeling Requirements for Inverter-based Resources (IBRs)

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## Abbreviations and Acronyms

**Table 1. Abbreviations and Acronyms**

Term	Definition
<b>BESS</b>	Battery Energy Storage System
<b>DEV</b>	Dominion Energy Virginia
<b>DEV-ET</b>	Dominion Energy Virginia Electric Transmission
<b>EMT</b>	Electromagnetic Transient
<b>FACTS</b>	Flexible AC Transmission Systems
<b>FERC</b>	Federal Energy Regulatory Commission
<b>HFRT</b>	High Frequency Ride Through
<b>HVRT</b>	High Voltage Ride Through
<b>IBR</b>	Inverter-based Resource
<b>IGBT</b>	Insulated Gate Bipolar Transistor
<b>LFRT</b>	Low Frequency Ride Through
<b>LVRT</b>	Low Voltage Ride Through
<b>NERC</b>	North American Electric Reliability Corporation
<b>PJM</b>	Pennsylvania–New Jersey–Maryland Interconnection
<b>PLL</b>	Phase-Locked Loop
<b>POI</b>	Point of Interconnection
<b>PPC</b>	Power Plant Controller
<b>PV</b>	Photovoltaic
<b>SCR</b>	Short-Circuit Ratio
<b>UDM</b>	User-defined Model

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## 1.0 SCOPE AND APPLICABILITY

Accurate models of inverter-based resources (IBRs) are a critical prerequisite for conducting power system studies in both the planning and operational timeframes. As such, all IBR Interconnection Customers seeking to interconnect to the DEV-ET system shall provide the following detailed, site-specific models and accompanying report(s) in accordance with the requirements set forth in this document:

- PSS/E steady state (power flow) model
- PSS/E positive sequence standard library dynamic model
- PSS/E positive sequence user-defined model (UDM)
- PSCAD electromagnetic transient (EMT) model, including both average and power electronic switching representations
- Aspen OneLiner short-circuit model

This document defines the model requirements, verification, and benchmarking test procedures, validation methods, and associated pass/fail criteria. These requirements are applicable to all IBRs, including solar photovoltaic (PV), Type III and Type IV wind plants, battery energy storage systems (BESSs), and co-located and hybrid plants comprised of combinations of these resource types that connect to the DEV-ET system.<sup>1</sup>

## 2.0 GENERAL REQUIREMENTS

The model requirements in this section apply to all five model types: the PSS/E steady-state model, PSS/E standard library model, PSS/E UDM, EMT model, and short-circuit model. Model-specific requirements for each model type and accompanying report(s) are detailed in the following sections.

The models shall be configured to match the installed (or planned) equipment in the field and include all controls and protections that could affect the electrical output of the IBR plant to the extent possible.


The models shall be provided in standalone packages (i.e., one folder per model type containing all necessary files), ready for simulations, and shall represent the project at the requested service level at the point of interconnection (POI) (i.e., maximum active power output). The control mode and the parameters shall be set as specified in applicable interconnection requests and contractual agreements.

The models shall have the capability to change the control mode to any control mode possible in the actual power plant (e.g., voltage droop control, reactive power control, or power factor control, etc.) with accessible and modifiable reference setpoints.

All IBR units of the same type (identical design) shall be combined into a single equivalent aggregated unit. All IBR unit transformers of the same type (identical design) shall be combined into a single equivalent aggregated IBR unit transformer. Each substation transformer (or main power transformer, MPT) should be modeled. Figure 1 shows a simplified single-line diagram of an aggregated<sup>2</sup> IBR plant for reference.

<sup>1</sup> This includes the high-voltage direct current (HVDC) systems that are deployed solely for interconnection of an IBR plant and excludes standalone HVDC systems.

<sup>2</sup> Aggregation should be used for identical designs and shall be avoided for differing types/designs. For example, if a PV plant uses two different solar inverters, one equivalent aggregated unit shall be used for each type of inverter.

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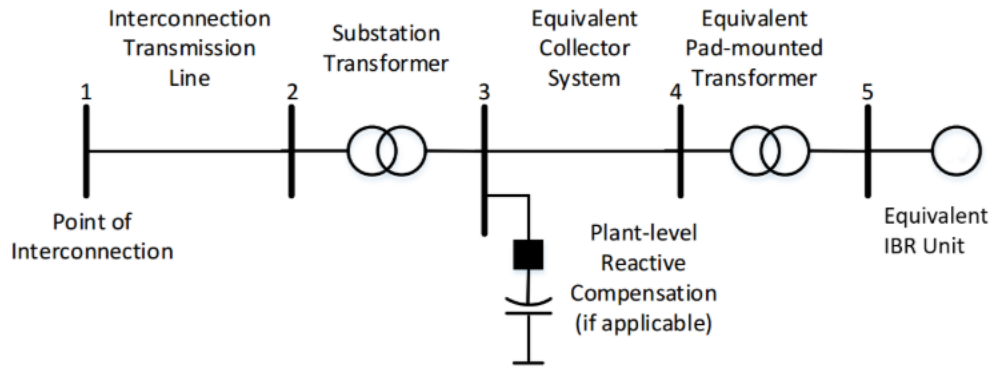


Figure 1. Simplified single-line diagram of an aggregated IBR plant

An IBR plant comprising different inverters with different reactive capabilities, control setups, and protection setups would need to use a multi-generator representation, as shown in Figure 2.

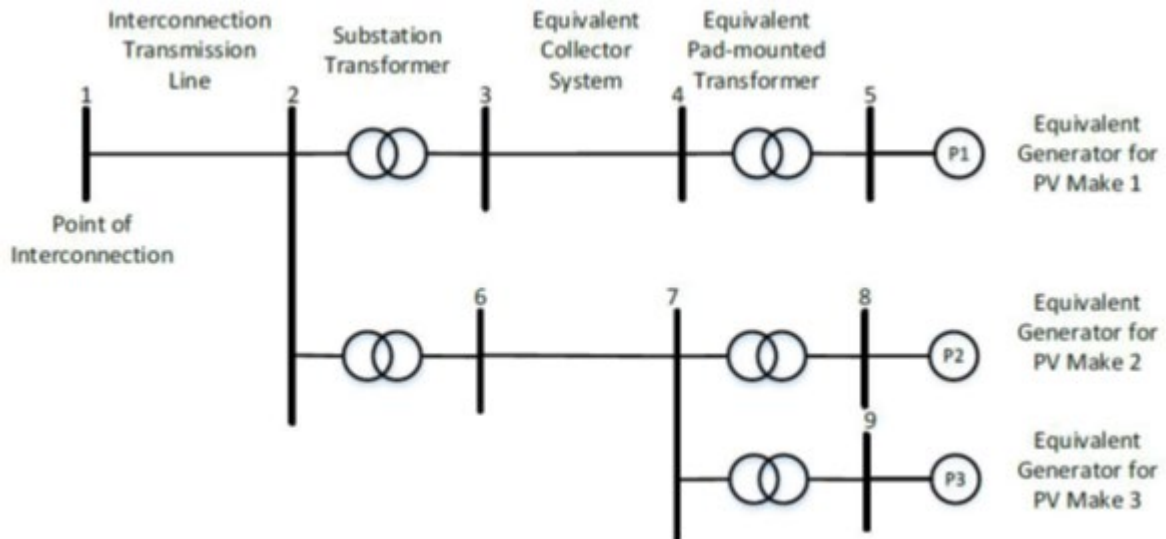



Figure 2. Simplified single-line diagram of a multiple-generator equivalent IBR plant<sup>3</sup>

<sup>3</sup> PJM, “PJM Dynamic Model Development Guidelines for Interconnection Analysis”, Rev. 1.1, Oct. 8, 2024. <https://www.pjm.com/-/media/DotCom/planning/services-requests/pjm-dynamic-model-development-guidelines.pdf>

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The collector system model shall be an equivalent representation of the collector system.<sup>4</sup>

All main power transformers and shunt compensation devices connected to the medium voltage collector bus(es) shall be explicitly modeled (i.e., no equivalencing).

The models (except for the short-circuit model) shall include site-specific component and control models for the following, as applicable:

1. IBR units
2. IBR unit transformers
3. Collector system
4. Mechanically switched reactive power devices<sup>5</sup>
5. Station service load
6. Flexible AC transmission systems (FACTS) devices<sup>6</sup>
7. Power plant controller (PPC)
8. IBR main transformer(s)
9. Gen-tie line

The PPC model shall include control of all devices that are controlled by the PPC (e.g., batteries, different inverter manufacturers, switchable shunts, D-STATCOM, etc.), if applicable.

The controls of mechanically switched reactive devices shall be modeled if the equipment dynamically responds to a disturbance within 10 seconds.

The controls of the main power transformer on-load tap changers (OLTC/ULTC) shall be modeled if the equipment dynamically responds to a disturbance within 10 seconds.

All models shall be developed for a system with a 60 Hz base frequency.

Each set of models shall include documentation that:


1. Describes the applicability, functional use, and capabilities of the model.
2. Describes any known limitations of the models (e.g., minimum SCR, model bandwidth, protection functions that are not included, control features that are not modeled, etc.).
3. Lists the files provided and their purpose (e.g., .obj, .dll, etc.).
4. Describes which PSSE, PSCAD, and Aspen OneLiner versions are supported (including Fortran Compiler for PSCAD models) and the minimum and maximum simulation time steps and other relevant simulation parameters.
5. Explains the control strategy of the PPC and the IBR unit controllers, together with the corresponding control block diagrams.
6. Defines and describes parameters within the model that correspond to 1) frequency droop, 2) frequency deadband, 3) voltage reactive power droop, and 4) fault ride-through and protection settings.

---

<sup>4</sup> E. Muljadi, A. Ellis, et al, "Equivalencing the Collector System of a Large Wind Power Plant", IEEE Power Engineering Society Annual Conference, Montreal, Quebec, June 12-16, 2006.

<sup>5</sup> E.g., shunt capacitor banks, shunt reactor banks, and harmonic filter banks.

<sup>6</sup> E.g., STATCOM and SVC.

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Moreover, a benchmarking report to demonstrate the models’ performance and a modeling checklist, which ensures that models are complete, accurate, and compliant, are to be completed and provided by the Interconnection Customer with every model’s submission. Submission of all models and documentation shall be made directly to DEV-ET through the designated DEV-ET Project Manager or alternate designated DEV-ET point of contact.

### 3.0 POSITIVE SEQUENCE MODELING REQUIREMENTS

Each IBR plant shall be represented with a PSS/E steady-state power flow model (.raw or .sav) and a set of dynamic models (.dvr). In compliance with FERC Order 2023, all new IBR interconnections must provide both a PSS/E standard library model and a PSS/E user-defined model (UDM). The former shall use the latest standard library<sup>7</sup> models available in PSSE. The PSS/E standard library model shall not use any models listed on the ERO Unacceptable Model List.<sup>8</sup> All models shall be configured and parameterized to be site-specific. The PSS/E version shall align with PJM’s requirement for the PSS/E version for interconnection queues.<sup>9</sup>

The PSS/E models shall represent all components up to the POI, including the following:

1. Aggregated IBR unit model
2. Aggregated IBR unit step-up transformer
3. Aggregated IBR unit electrical controls and protections that can be modeled
4. For wind turbine generators, appropriate mechanical models
5. PPC, representing overall site control of all applicable equipment
6. Voltage and frequency ride-through capability and protection settings, including IBR unit settings and balance of plant relay settings
7. MPT; test reports shall also be attached
8. MPT controls, such as on-load tap changer (OLTC)
9. Aggregate collector system equivalent; evidence of equivalencing shall also be attached
10. Supplemental IBR devices such as FACTS
11. Mechanically switched reactive power devices
12. Generation interconnection facilities, such as a gen-tie line
13. Balance of plant voltage and frequency protection settings

### 4.0 ELECTROMAGNETIC TRANSIENT MODELING REQUIREMENTS

The EMT models shall include a detailed representation of the inverter controls, protection schemes, and any relevant auxiliary systems necessary to capture fast EMTs and control interactions.

The next subsections describe specific requirements for developing EMT models to ensure consistency and accuracy.


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<sup>7</sup> Standard library models are often referred to as “generic models”; however, each model submitted shall be appropriately parameterized to be site-specific.

<sup>8</sup> NERC Dynamic Modeling Recommendations - Appendix A: NERC Unacceptable Model List

<https://www.nerc.com/pa/RAPA/ModelAssessment/Documents/Dynamic%20Modeling%20Recommendations.pdf>

<sup>9</sup> Table 1 “PSS/E Versions by Queue/Cycle” in “PJM Dynamic Model Development Guidelines for Interconnection Analysis”, Rev. 1.1, Oct. 8, 2024. <https://www.pjm.com/-/media/DotCom/planning/services-requests/pjm-dynamic-model-development-guidelines.pdf>

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#### 4.1 Model Accuracy

The following components should be modelled in detail:

1. Full inner control loop. The manufacturer’s models that embed the actual firmware code shall be used.
2. All control features, such as PPC, phase-locked loop (PLL), phase-jump detection, signal conditioning methods, communication delays, controller cycling delays, external voltage controllers, etc.
3. All protection systems, both at the IBR unit level and at the plant level.
4. Both the full Insulated Gate Bipolar Transistor (IGBT) representation (also referred to as a discrete switch model<sup>10</sup>) and the average model of the IBR unit shall be provided.
5. User-accessible parameters for all control models.
6. Shunt capacitors, reactor banks, and other dynamic reactive devices.
7. All pertinent electrical and mechanical configurations (filters, transformers, including saturation, wind-turbine control, etc.)
8. PLL protection, if implemented.
9. Facilities from POI to MPT lower side shall be explicitly modeled. Feeder, collector system, IBR unit transformer, and IBRs shall be aggregated per resource type if the aggregated inverters are of the same control and protection. In specific cases, Dominion Energy may require the Interconnection Customer to submit detailed EMT models.
10. EMT and short-circuit models shall include grounding transformer(s), if used.
11. The EMT model shall include DC-side dynamics, control, and protection of the inverter/converter.
12. IBR unit transformers and IBR MPT models shall include the saturation characteristic of the core. This includes the per-unit air core reactance, the per-unit knee voltage, and the per-unit magnetizing current. This is required only for models submitted after commissioning.
13. Gen-tie lines should be modeled using the Bergeron model.


#### 4.2 Model Usability

To ensure usability and interoperability with other models, the following criteria shall be followed:

1. Control and hardware options should be user-accessible. All options and configuration settings that are available in the actual devices shall be made accessible in the EMT model. This includes, but is not limited to, active and reactive power modes, ramp rates and settings, diagnostic flags (e.g., flags to show control mode changes or which protection has been activated), etc.
2. Timestep between 10  $\mu$ s and 20  $\mu$ s shall be used for the average model, and the model shall not be restricted to a specific timestep value. The full switching model can use a smaller time-step, if needed.
3. Given a set of initial conditions, the model shall self-initialize without requiring any interaction from the user.
4. The model shall accept external reference values both at initialization and during a simulation run.
5. The user shall be allowed to disable specific protections, based on the study to be performed.
6. The rating of the plant shall be scalable, either internally or using a scaling transformer.
7. The model shall allow multiple instantiations (i.e., several elements of the same type shall be able to use the same .dll, where applicable).

---

<sup>10</sup> CIGRE TB727, “Modelling of inverter-based generation for power system dynamic studies”, <https://www.e-cigre.org/publications/detail/727-modelling-of-inverter-based-generation-for-power-system-dynamic-studies.html>

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8. Documentation and a sample implementation case illustrating the main functions of the model shall be provided.

#### **4.3 Model Efficiency**

1. Models shall be developed using PSCAD version 5 or higher. However, models should not be dependent on a specific PSCAD version to run correctly.
2. Blackbox models shall be compiled using the Intel Fortran compiler but shall not be dependent on a specific version.
3. The model shall initialize to its ordered initial conditions within 3 seconds.
4. The model shall support multiple instances in the same project.
5. The model shall support the PSCAD “snapshot” and “multiple run” features.

### **5.0 SHORT-CIRCUIT MODELING REQUIREMENTS**

Short-circuit models are required to perform studies and ensure that protection relays are set to 1) detect the fault effectively, 2) be coordinated, and 3) the circuit breaker capabilities are not exceeded. The short-circuit model shall be a .olr file compatible with ASPEN OneLiner version 15.7.

The short-circuit models shall include appropriate representation of all components up to POI, including the following:

1. Each MPT shall be modeled
2. IBRs on the low side of MPT can be aggregated
3. Voltage and frequency control of IBRs and PPCs
4. Breakers rated at 100 kV and above
5. Generation interconnection facilities, such as gen-tie lines owned by or jointly owned by the Interconnection Customer, and corresponding relays
6. Reactive power devices, such as capacitor banks and FACTS

Equivalent positive, negative, and zero sequence data shall be reflected accurately in the model, including but not limited to line and transformer impedance.


IBR shall be modeled using Converter-Interfaced Resource (CIR), as recommended by ASPEN Oneliner. The model parameters, such as negative-sequence current injection and current limits, shall match the OEM’s datasheet and/or the inverter settings.

### **6.0 MODEL VERIFICATION PROCEDURE**

Model verification is the process of confirming that model structure and parameter values are representative of the equipment or facility design and settings by reviewing equipment or facility design and setting documentation.

Together with the model, the Customer should submit a model verification report. In both the steady-state and dynamic models, the model verification should cover at least the following:

- Generator and energy storage (type, size, etc.)
- Collection system (equivalent impedance and calculation)
- Inverter control

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- Main power transformer
- On-Load Tap Changer (OLTC) settings of MPT
- Power plant controller
- Plant protection settings
- Gen-tie line
- Dynamic reactive power equipment and FACTS devices (if any)

The model verification report should verify both the model structure and parameters. The model verification report shall be submitted after commissioning and before the commercial operation day (COD). For any parameter changes made after COD that affect the IBR plant's electrical output, the updated model verification report shall be submitted within 30 days of the changes.

### 6.1 OEM Attestation

Attestations from the OEM that the model represents the planned or installed equipment, based on the available information at the time of submission, are required for the IBR unit and the PPC. Complementary examples of acceptable approaches for model verification include, but are not limited to, the following:

1. Mapping of the controller's code firmware version to the model version for real-code models.
2. Evidence that the model parameters represent the planned control and protection settings, as detailed in Section 6.3.

### 6.2 Model Structure

Only the models from the PJM acceptable model list are acceptable for the standard library model.<sup>11</sup>

For the UDM model of both positive sequences, the control block diagram and datasheet shall be included in the report. The control parameters used in the model shall be marked in the control block diagram. For the EMT model, a high-level description is required if the block diagram is unavailable.

### 6.3 Parameters


The report should include a table to compare the parameters of different models and the in-field settings. A short description for each parameter should be added. An example is given in Table 15. Model Verification Table (example) in Section 11 of this attachment. At a minimum, the parameters in Table 14. Model Parameters Comparison in Section 11 of this attachment shall be included.

Scaling factors and unit conversions shall be included in the report. The report shall identify and justify any differences between field parameter settings and model parameter settings.

The as-built parameter settings shall be exported directly from the commissioned IBR units, PPC, and other controlled devices with timestamp information.

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<sup>11</sup> Appendix A-2 of "PJM Guidance for NERC MOD-026-027 Generation Owner Preparation & Submittal", accessible from <https://www.pjm.com/-/media/DotCom/library/whitepapers/compliance/20231017-guidance-for-go-to-prepare-nerc-mod-026-027-and-submittal.pdf>

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## 7.0 MODEL BENCHMARK REPORT

A report comparing the response of all required models to the specific disturbances described in Section 7.1 shall be provided. The goal of the report is to show that the generic positive sequence models and the EMT model reasonably match each other in simulated behavior and parametrization. The response of the IBR in all benchmark tests shall be stable, reasonably damped, and exhibit a reasonable dynamic response. DEV-ET reserves the right to review all benchmark test results and seek clarifications, as needed.

A new report shall be provided whenever changes or updates are made to any of the models.

For co-located IBR plants, a summary test report shall be submitted for each IBR plant unit. If the IBR plant is a hybrid resource comprising multiple resource types, a summary test report shall be submitted for each resource type. For example, if the IBR plant consists of a solar PV plus BESS combination, then the following three model submittal packages are required, where the following operations are applicable:

- Solar PV operating individually
- BESS operating individually
- Solar PV and BESS operating in parallel

### 7.1 Benchmark tests

All tests shall use a simulation duration of at least 30 seconds. The report shall contain the results of the following tests:

**7.1.1 30-Second-Flat Run**

**Table 2. 30-Second Flat Run**

Test No.	Disturbance	IBR Plant Initial Condition			Grid Initial Condition	
		Active Power at the POI	Reactive Power at the POI	Voltage at the POI (pu)	Infinite Bus Voltage	SCR
<b>Standalone IBR Plant</b>						
7.1.1-1	No disturbance	Pmax	Qmax	1.0	Rated voltage at POI	5
7.1.1-2	No disturbance	Pmax	Qmin	1.0	Rated voltage at POI	5
7.1.1-3	No disturbance	Pmin <sup>12</sup>	Qmax	1.0	Rated voltage at POI	5
7.1.1-4	No disturbance	Pmin <sup>13</sup>	Qmin	1.0	Rated voltage at POI	5
<b>Hybrid Site</b>						
7.1.1-1	No disturbance	Pmax (Solar/Wind 100%, BESS 0%)	Qmax	1.0	Rated voltage at POI	5
7.1.1-2	No disturbance	Pmax (Solar/Wind 100%, BESS 0%)	Qmin	1.0	Rated voltage at POI	5
7.1.1-3	No disturbance	Pmax (Solar/Wind 0%, BESS 100%)	Qmax	1.0	Rated voltage at POI	5
7.1.1-4	No disturbance	Pmax (Solar/Wind 0%, BESS 100%)	Qmin	1.0	Rated voltage at POI	5
7.1.1-5	No disturbance	Pmin <sup>14</sup>	Qmax	1.0	Rated voltage at POI	5

<sup>12</sup> Applicable only to BESS plants. Pmin implies the maximum allowable charging active power level.

<sup>13</sup> Applicable only to BESS plants. Pmin implies the maximum allowable charging active power level.

<sup>14</sup> Pmin implies the maximum allowable charging active power level with the IBR generator type (e.g., solar) at 0 MW.

7.1.1-6	No disturbance	Pmin <sup>15</sup>	Qmin	1.0	Rated voltage at POI	5
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### 7.1.1.1 Pass/Fail Criteria

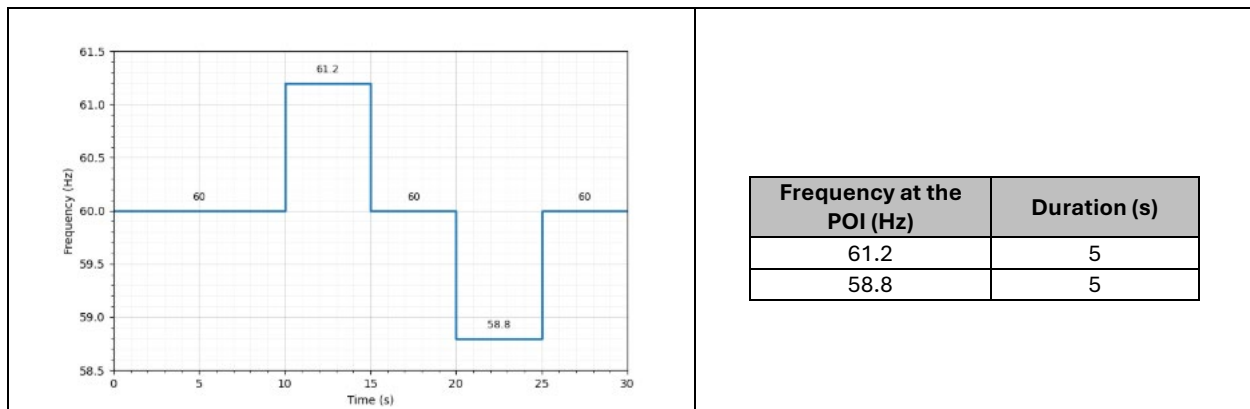
The models pass these tests if all the following conditions are met for each test:

1. PSSE models initialize without any initial suspect errors, and the results remain flat throughout the simulation.
2. PSCAD models shall reach a steady state in less than 5 seconds and remain flat during the remainder of the simulation run.
3. Active, reactive, and voltage values shall reasonably match between the PSSE standard library model, PSSE UDM, and PSCAD models at the POI.

### 7.1.2 Response to Small Disturbance Frequency Step Change from Nominal Frequency (60 Hz)

**Table 3. Response to small disturbance frequency step change from nominal frequency (60 Hz)**

Test No.	Disturbance	IBR Plant Initial Condition			Grid Initial Condition	
		Active Power at the POI	Reactive Power at the POI	Frequency at the POI (pu)	Infinite Bus Voltage	SCR
7.1.2-1	± 2% frequency step change	Pmax	0	Figure 3	Rated voltage at POI	5



**Figure 3. Frequency profile with data values at the POI for the frequency step tests**

<sup>15</sup> Pmin implies the maximum allowable charging active power level with the IBR generator type (e.g., solar) at 0 MW.

7.1.2.1 Pass/Fail Criteria

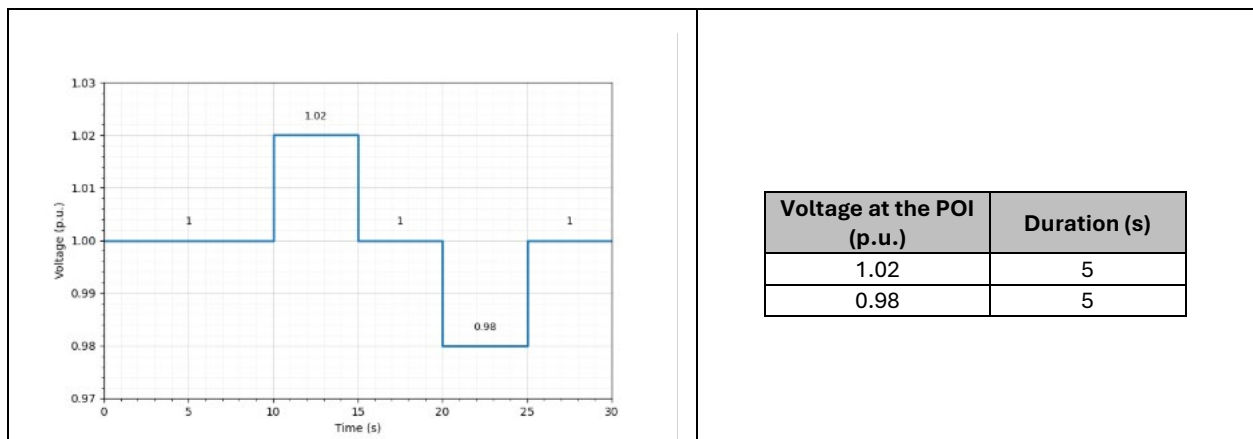
The models pass these tests if all the following conditions are met for each test:

1. The plant shall not trip and shall have a stable and well-damped response.
2. Appropriate active power response shall be observed based on control settings.
3. Active, reactive, and voltage values shall reasonably match between PSSE standard library model, PSSE UDM, and PSCAD models at the POI.

7.1.2.2 Response to Small Disturbance Voltage Step Change from Scheduled Voltage at POI (If Not Known, Use Rated Voltage at POI)

**Table 4. Response to small disturbance voltage step change from scheduled voltage at POI (if not known, use rated voltage at POI)**

Test No.	Disturbance	IBR Plant Initial Condition			Grid Initial Condition	
		Active Power at the POI	Reactive Power at the POI	Voltage at the POI (pu)	Infinite Bus Voltage	SCR
7.1.3-1	± 2% voltage step change	Pmax	0	Figure 4	Rated voltage at POI	5



**Figure 4. Voltage profile with data values at the POI for the voltage step tests**

7.1.2.3 Pass/Fail Criteria

The models pass these tests if all the following conditions are met for each test:

1. The plant shall not trip and shall have a stable and well-damped response.
2. The plant shall not enter momentary cessation (current blocking) mode.
3. Appropriate reactive power response shall be observed based on control settings.
4. Active, reactive, and voltage values shall reasonably match between PSSE standard library model, PSSE UDM, and PSCAD models at the POI.

### 7.1.3 Response to 9-Cycle Three-Phase Fault at POI

**Table 5. Response to 9-cycle three-phase fault at POI**

Test No.	Disturbance	IBR Plant Initial Condition			Grid Initial Condition
		Active Power at the POI	Reactive Power at the POI	Voltage at the POI (pu)	Infinite Bus Voltage
7.1.4-1	Bolted 3LG Fault	Pmax	Qmax	1.0	Rated voltage at POI

- Bolted 3LG fault: A three-phase-to-ground fault with zero fault impedance is applied at the POI at t = 10 seconds and cleared after 9 cycles (i.e., 0.15 seconds).

#### 7.1.3.1 Pass/Fail Criteria

The models pass these tests if all the following conditions are met for each test:

1. The plant shall not trip and shall have a stable and well-damped response. An acceptable damping is 3% or greater.
2. If the plant enters momentary cessation (current blocking) mode, it must resume current injection in no less than 5 cycles following voltage recovery.
3. After fault clearing and voltage recovery within the normal range, the active power recovery time to the pre-fault value shall be within 1.0 second, unless a different recovery time is approved by DEV-ET.
4. Active, reactive, and voltage values shall reasonably match between the PSSE standard library model, PSSE UDM, and PSCAD models at the POI.
5. Current injection from the IBR during the fault shall reasonably match between the PSCAD and Aspen OneLiner models.

### 7.1.4 High-Voltage Ride-Through (HVRT) and Low-Voltage Ride-Through (LVRT) Tests

The power plant and its model should be in compliance with Dominion Energy Voltage Ride-through Requirements as defined in the corresponding FIR Attachment (plant should continue to inject current within the No-Trip-Zone).

**Table 6. High-Voltage Ride-Through (HVRT) and Low-Voltage Ride-Through (LVRT) Tests**

Test No.	Disturbance	IBR Plant Initial Condition			Grid Initial Condition
		Active Power at the POI	Reactive Power at the POI	Voltage at the POI (pu)	Infinite Bus Voltage
7.1.5-1	High Voltage	Pmax	0	69 – 499 kV: Figure 4 (a) 500 kV: Figure 4 (b)	Rated voltage at POI
7.1.5-2	Low Voltage	Pmax	0	Figure 4 (c)	Rated voltage at POI



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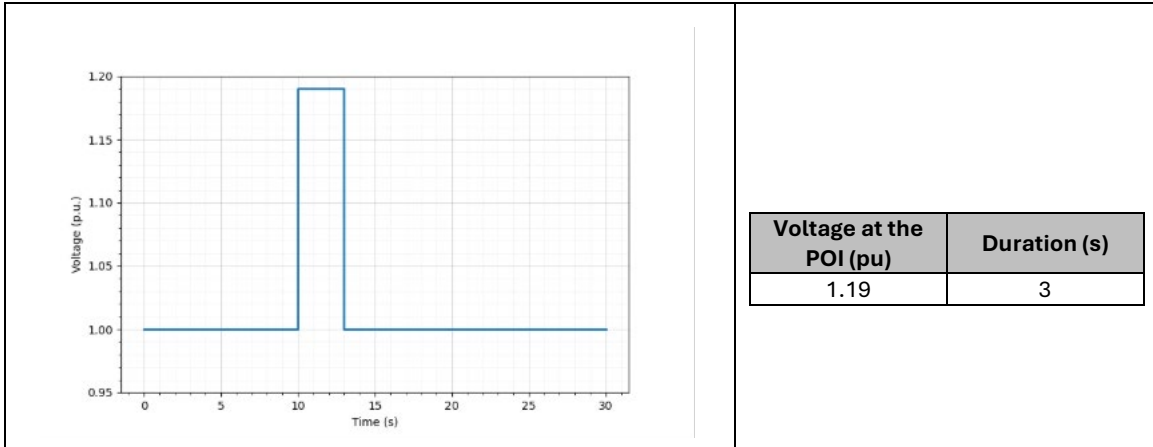
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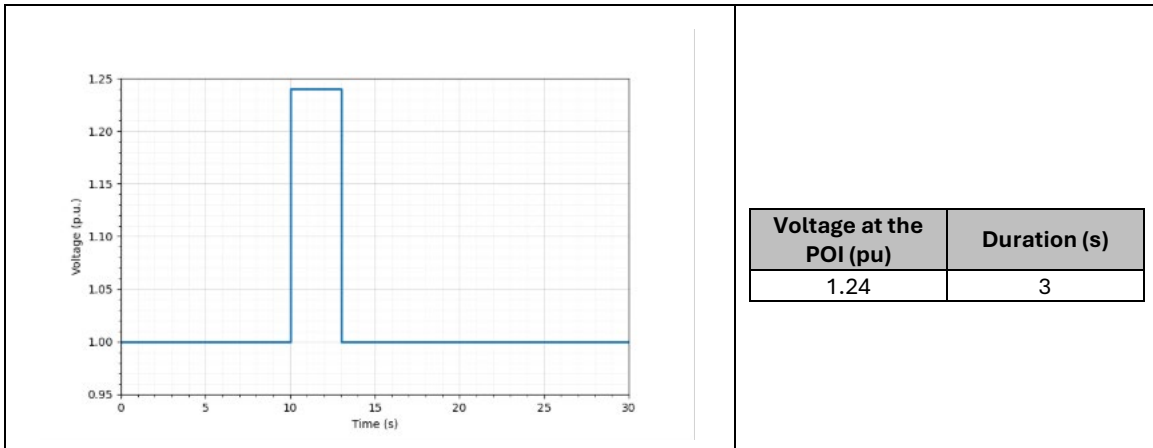
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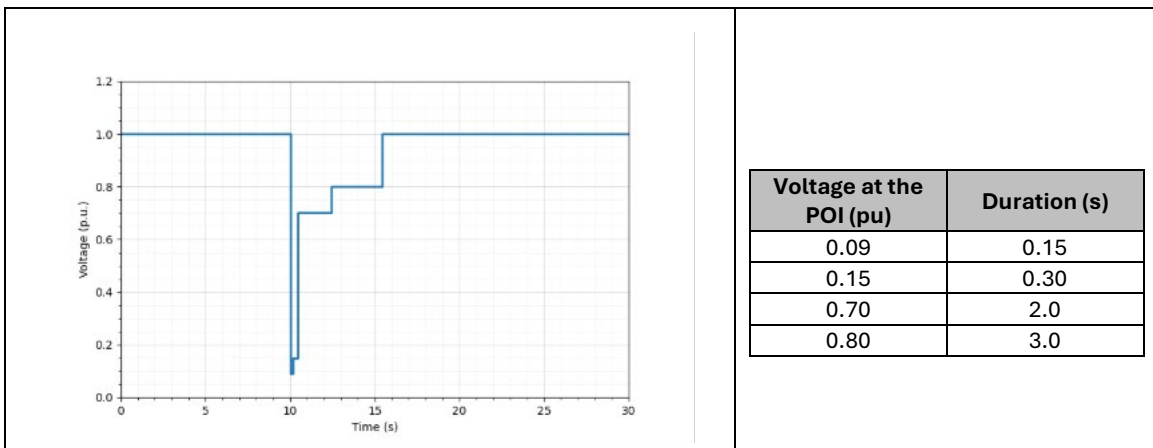
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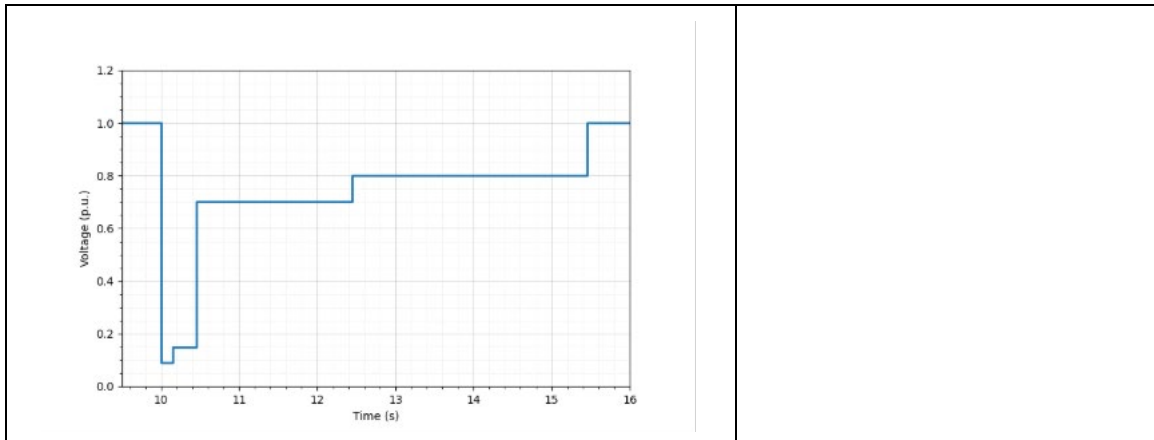


**Figure 5. Voltage profile with data values at the POI for the HVRT and LVRT tests: HVRT test for 69 kV-499 kV**



**Figure 6. Voltage profile with data values at the POI for the HVRT and LVRT tests: HVRT test for 500 kV**





**Figure 7. Voltage profile with data values at the POI for the HVRT and LVRT tests: LVRT test for 69 kV – 500 kV (zoomed-out and zoomed-in)**

#### 7.1.4.1 Pass/Fail Criteria

The models pass these tests if all the following conditions are met for each test:

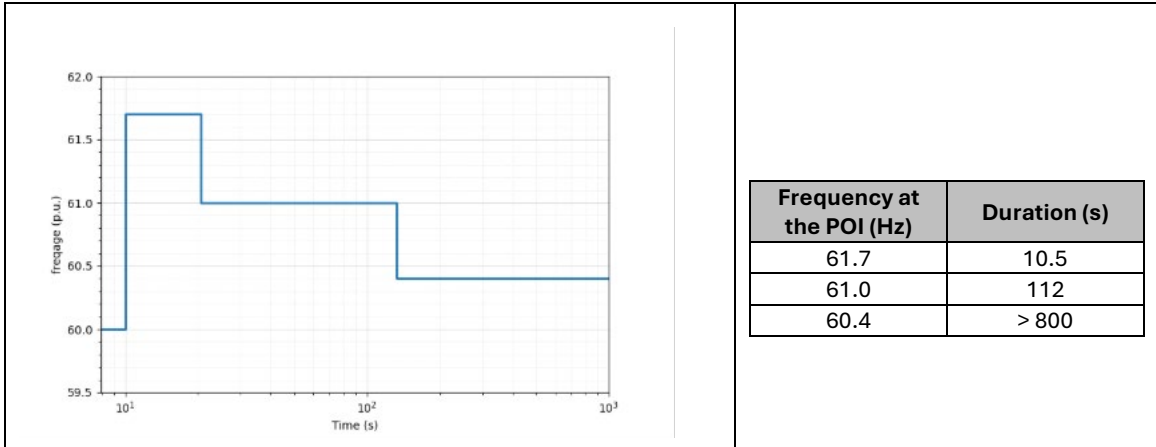
1. The plant shall not trip and shall have a stable and well-damped response. An acceptable damping is 3% or greater.
2. The plant shall not enter momentary cessation (current blocking) mode.
3. If active power is reduced, it should recover to the pre-disturbance value within 1.0 second after the disturbance, unless a different recovery time is approved by DEV-ET.
4. Appropriate reactive power response shall be observed based on control settings.
5. Active, reactive, and voltage values shall reasonably match between PSSE standard library model, PSSE UDM, and PSCAD models at the POI.

#### 7.1.5 High-Frequency Ride-Through (HFRT) and Low-Frequency Ride-Through (LFRT) Tests

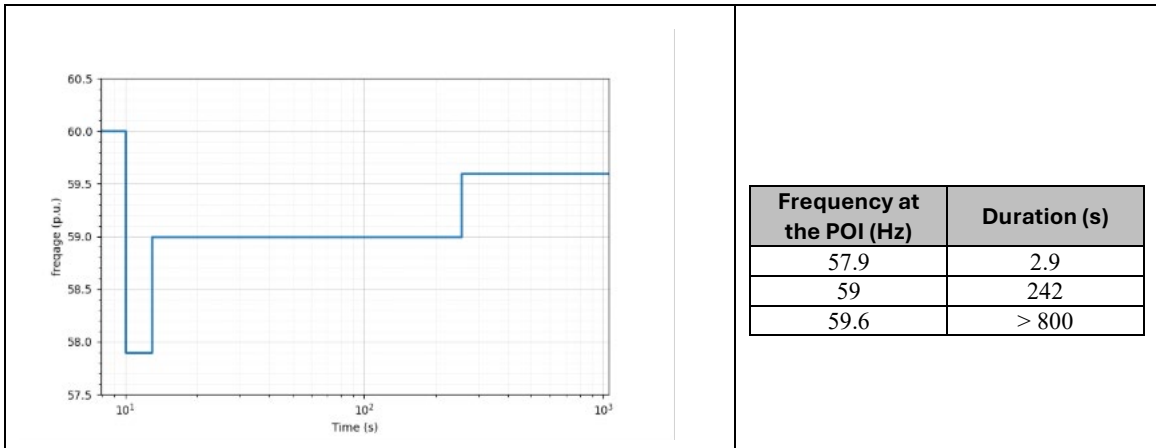
The power plant and its model should be in compliance with Dominion Energy Frequency Ride-through Requirements as defined in the corresponding FIR Attachment (plant should continue to inject current within the No-Trip-Zone).

**Table 7. High-Frequency Ride-Through (HFRT) and Low-Frequency Ride-Through (LFRT) Tests**

Test No.	Disturbance	IBR Plant Initial Condition			Grid Initial Condition
		Active Power at the POI	Reactive Power at the POI	Frequency at the POI (Hz)	Infinite Bus Voltage
7.1.6-1	High Frequency	Pmax	0	Figure 5(a)	Rated voltage at POI
7.1.6-2	Low Frequency	Pmax	0	Figure 5(b)	Rated voltage at POI



**Figure 8. Frequency profile with data values at the POI for the HFRT test**



**Figure 9. Frequency profile with data values at the POI for the LFRT test**

### 7.1.5.1 Pass/Fail Criteria

The models pass these tests if all the following conditions are met for each test:

1. The plant shall not trip and shall have a stable and well-damped response. An acceptable damping is 3% or greater.
2. The plant shall not enter momentary cessation (current blocking) mode.
3. If active power is reduced, it should recover to the pre-disturbance value within 1.0 second after the disturbance, unless a different recovery time is approved by DEV-ET.
4. Appropriate reactive power response shall be observed based on control settings.
5. Active, reactive, and voltage values shall reasonably match between PSSE standard library model, PSSE UDM, and PSCAD models at the POI.

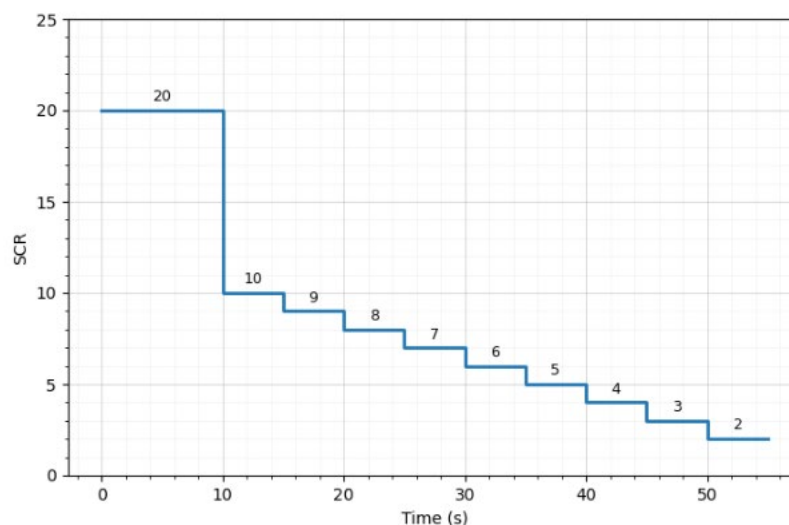
### 7.1.6 Stability at Varying System Strength Conditions

For short-circuit ratios (SCR) ranging from SCR = 10 to SCR = 2, in steps of 1, a 9-cycle 3-phase fault is applied, and stability is demonstrated for each condition, independently.

**Table 8. Update**

Test No.	Disturbance	IBR Plant Initial Condition			Grid Initial Condition	
		Active Power at the POI	Reactive Power at the POI	Voltage at the POI (pu)	Infinite Bus Voltage	SCR
7.1.7-1	SCR change + Bolted 3LG fault.	Pmax	0	1.0	Rated voltage at POI	Figure 6

- Disturbance: Change the SCR of the grid, as shown in Figure 10. At the beginning of each transition to the next SCR value, apply a three-phase-to-ground fault with zero fault impedance at the POI and clear the fault after 9 cycles (i.e., 0.15 seconds).




**Figure 10. Short circuit ratio profile with data values of the grid for SCR tests**

#### 7.1.6.1 Pass/Fail Criteria

The models pass these tests if all the following conditions are met for each test:

- The plant shall not trip and shall have a stable and well-damped response until at least SCR=2.5 (i.e., time 50 seconds in Figure 10). An acceptable damping is 3% or greater.
- Active, reactive, and voltage values shall reasonably match between PSSE standard library, PSSE UDM, and PSCAD models at the POI.

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## 7.2 Sample Report

Figure 11 through Figure 14 show an example response of a generic IBR model during a three-phase fault test (Test 7.1.4-1) from the three models: PSSE standard library model, PSSE UDM, and PSCAD model. The test results demonstrate the IBR unit model response meeting the Pass Criteria performance requirements detailed in Section 7.1.4. The following details in an IBR unit model report for each test result are noted from the example:

- For each test, results shall be submitted in the template result format provided in Figure 11 through Figure 14.
- When submitting the test result, the example plots and test number in Figure 11 through Figure 14 shall be removed and replaced with the actual test number and results.
- Each measurement (frequency, voltage, active power, and reactive power) should include two plots: one zoomed-out plot showing the whole simulation period (including initialization) and one zoomed-in plot showing the time period of disturbance and post-disturbance recovery. This provides the details of the disturbance response, especially when a large fluctuation exists in the initialization period.
- Each test result shall have the test number and its associated eight separate plots that include labeled axes.
- A plot legend shall be included to detail the type of models (i.e., PSSE standard library model, PSSE UDM, and PSCAD model) overlaid on the same plot.

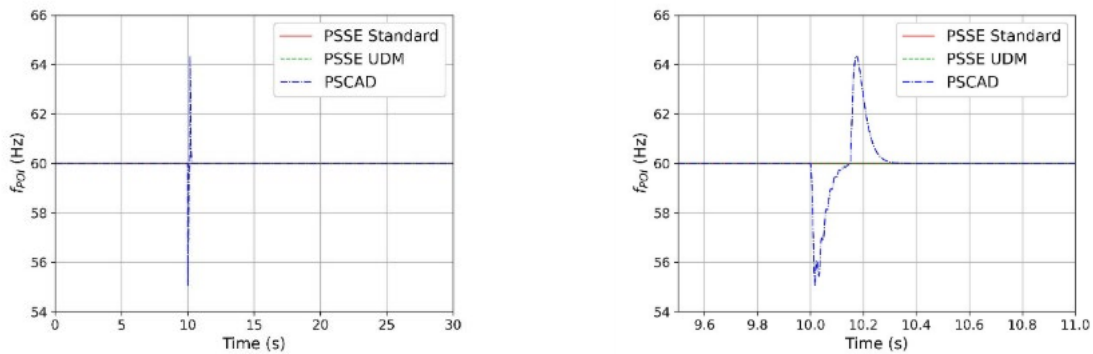
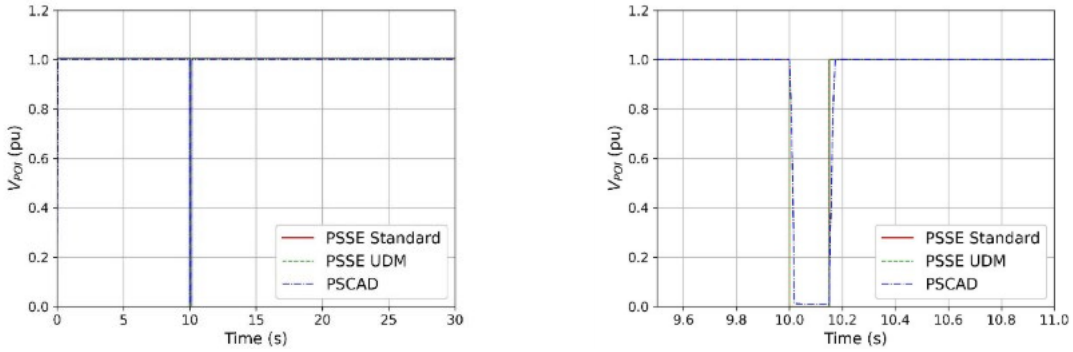
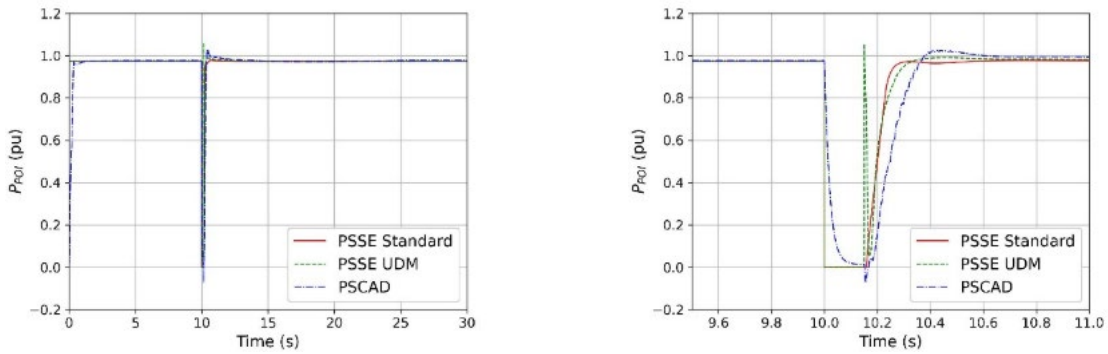


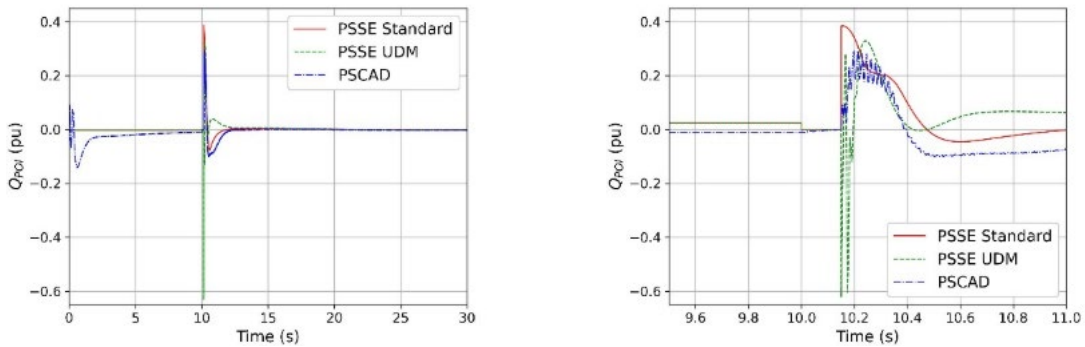
Figure 11. Acceptable frequency at the POI



**Figure 12. Acceptable voltage at the POI**



**Figure 13. Acceptable active power at the POI**



**Figure 14. Acceptable reactive power at the POI**

Figure 15 through Figure 18 show an example of unacceptable responses for the same three-phase fault test.



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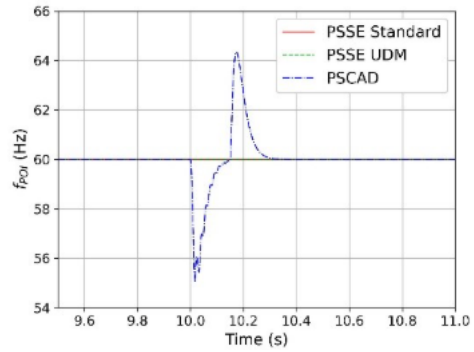
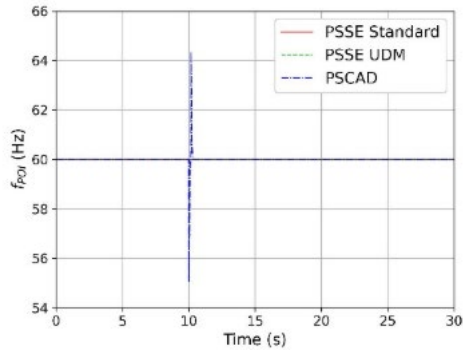


Figure 15. Unacceptable frequency at the POI

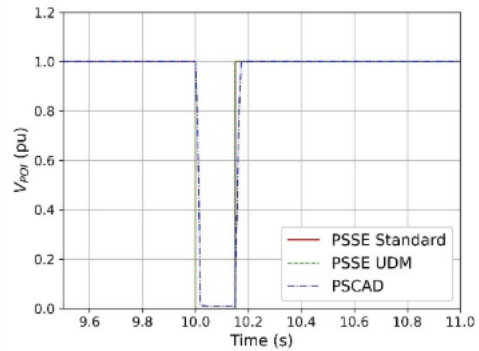
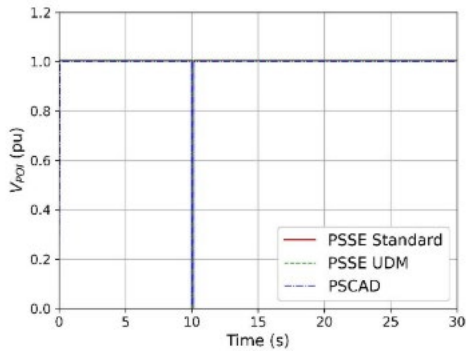


Figure 16. Unacceptable voltage at the POI

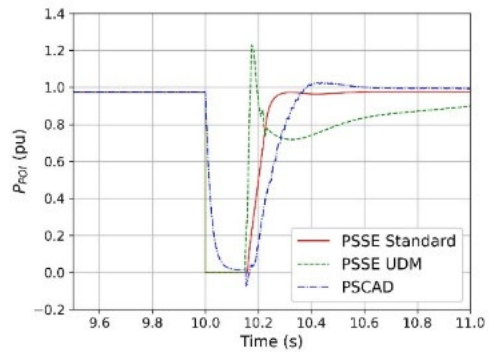
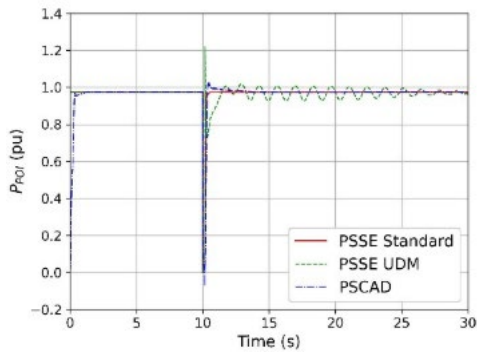

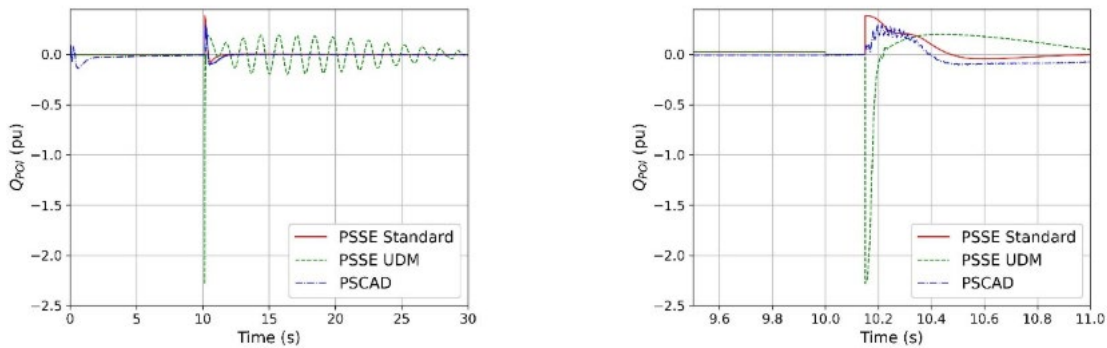


Figure 17. Unacceptable active power at the POI

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**Figure 18. Unacceptable reactive power at the POI**

## 8.0 MODEL VALIDATION PROCEDURE

Model validation is the process of comparing measurements with simulation results to assess how closely a model’s behavior matches the measured behavior.<sup>16</sup>

IBR unit model validation shall be performed using type tests conducted by the inverter OEM. Acceptable model validation methods include factory testing or hardware-in-the-loop (HIL) tests demonstrating that the IBR unit model’s response matches the IBR unit’s response for large-signal disturbances. Each IBR unit model deployed at the site shall have a validation report provided by the OEM. The Interconnection Customer shall provide the IBR unit model validation report to DEV-ET.


## 9.0 MODEL MODIFICATION AND RESUBMISSION REQUIREMENTS

### 9.1 Modifications that Require a Model Resubmission

Any modifications that affect the electrical behavior or dynamic response of an IBR plant are considered qualified changes that require model resubmission. Examples of changes may include: modifications to IBR unit settings and parameters; changes in control mode; updates to balance-of-plant protections that affect ride-through; changes to inverter make and model; modifications to PPC settings; reactive power device control changes; and main power transformer or load tap changer control changes.

Modifications can be made both before and after commissioning. Any change made prior to commissioning shall be communicated to DEV-ET, and updated models and reports shall be provided accordingly. Additionally, for changes after commissioning, the Interconnection customer shall use the established DEV-ET change management process prior to field implementation. Model resubmission should include all the documents, models, and data that were submitted before but are subject to update due to the change of model. If the change happens after model verification, benchmarking test, and/or validation, an updated

<sup>16</sup> [https://www.nerc.com/globalassets/standards/projects/2020-06/2020-06-model-definitions-initial-posting\\_april\\_17\\_2025.pdf](https://www.nerc.com/globalassets/standards/projects/2020-06/2020-06-model-definitions-initial-posting_april_17_2025.pdf)


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corresponding report(s) shall be submitted together with their required attachments. Resubmitted models should also state the changes been made and the performance they will affect.

Changes that have been determined by the change management process not to affect the electrical behavior or dynamic response of the IBR plant do not require model resubmission. A written statement of the changes shall be submitted for review and documentation purposes within 30 calendar days of the change. The Interconnection Customer shall raise any questions regarding whether a change requires model resubmission to Dominion Energy.

## 10.0 MODEL SUBMITTAL PROCESS FLOW

1. **Signing Generation Interconnection Requirement (GIA):** The Interconnection Customer is to make the first submission of the positive-sequence model, EMT model, and the accompanying report within 30 days of signing the GIA.
2. **Commissioning:** The Interconnection Customer shall update the model at Facility commissioning to accurately reflect the final as-built characteristics of the site and include all controls and protections that could affect the electrical output of the IBR plant to the extent possible. Any changes to previously submitted models shall be agreed upon by DEV-ET before commercial operation is authorized.
3. **First Year of Operation:** A revised set of models shall also be provided as part of the NERC MOD-26 and MOD-27 submissions by the Interconnection Customer, within the first year of operation: following the field tests detailed in the standards, the models shall be tuned to accurately match the IBR response.


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## 11.0 REQUIRED MODEL AND DOCUMENTATION

If additional space is needed, please attach supplementary information at the end of the application.

**Table 9. Generation Information**

General Information	
IBR plant name	
PJM queue number	
IBR plant POI	
POI nominal voltage [kV]	
Inverter manufacturer(s) and model(s)	
Contact information of individual(s) completing this form (name, email, phone number)	


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**Table 10. Positive Sequence Model**

Positive Sequence Model			
Model type		Provided? (Y/N)	Comments
Standard library model			
User-defined model			
Component		Modeled? (Y/N)	Comments
2.1	Generator and/or converter		
2.2	IBR unit step-up transformer		
2.3	Electrical controls		
2.4	Power plant controller (PPC)		
2.5(a)	Voltage ride-through		
2.5(b)	Frequency ride-through		
2.6	Main plant transformer(s)		
2.7	Aggregate collector system		
2.8	Supplemental IBR devices		
2.9	Mechanically-switched reactive power devices		
2.10	For wind turbines, mechanical controls		
2.11	Generation interconnection facilities, such as gen-tie		
Documentation		Provided? (Y/N)	Comments
2.12	Transformer test report		
2.13	Collector system equivalencing calculations		

**Table 11. EMT Model**

EMT Model			
Requirement		Implemented? (Y/N)	Comments
<b>Model Accuracy</b>			
3.1.1	Full inner control loop		
3.1.1	OEM firmware embedded		
3.1.2	All controls modeled		
3.1.3	All protection systems		
3.1.4	Discrete switch model (full IGBT representation) and average model		
3.1.5	User-accessible control parameters		
3.1.6	Reactive devices		
3.1.7	Electrical and mechanical configurations		
3.1.8	PLL protection		
<b>Model Usability</b>			
3.2.1	User-accessible hardware and control configurations		
3.2.2	Timestep between 10 $\mu$ s and 20 $\mu$ s		
3.2.3	Self-initialize		
3.2.4	External reference values		
3.2.5	Protections can be disabled		
3.2.6	Scalable plant rating		
3.2.7	Documentation and sample case		
<b>Model Efficiency</b>			
3.3.1	PSCAD 5 or higher		
3.3.2	Intel Fortran compiler		
3.3.3	Quick initialization		
3.3.4	Multiple instances support		
3.3.5	“Snapshot” support		
3.3.5	“Multiple Run” support		

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**Table 12. Benchmark Report**


Benchmark Report			
Benchmark Test		Performed? (Y/N)	Comments
4.1.1	(For hybrid) Each individual and in-parallel test		
4.1.1-1	Flat run (maximum reactive power)		
4.1.1-2	Flat run (minimum reactive power)		
4.1.2-1	Frequency step change		
4.1.3-1	Voltage step change		
4.1.4-1	Three-phase fault at POI		
4.1.5-1	High voltage ride-through		
4.1.5-2	Low -voltage ride-through		
4.1.6-1	High-frequency ride-through		
4.1.6-2	Low-frequency ride-through		
4.1.7-1	Stability at varying SCR		

**Table 13. Short-Circuit Model**


Short-Circuit Model			
Model Format and Version		Provided? (Y/N)	Comments
.olr file compatible with ASPEN Oneliner version 15.7			
Component		Modeled? (Y/N)	Comments
4.1	Each MPT		
4.2	IBR units or aggregated IBRs		
4.3	Voltage and frequency control of IBRs and PPCs		
4.4	Breakers rated at 100 kV and above		
4.5	Generation interconnection facilities and corresponding relays, e.g., gen-tie line		
4.6	Reactive power devices		
Documentation		Provided? (Y/N)	Comments
4.7	Transformer test report		
4.8	Aggregated IBR model calculation		
4.9	Documents supporting voltage and frequency control of 4.3 above		

**Table 14. Model Parameters Comparison**

Model Parameters Comparison			
Equipment	Parameter	PSSE Model	PSCAD Model
IBR Plant	Facility maximum facility output (MFO) at POI		
	Total Plant MVA (Mbase)		
	Single inverter nameplate MVA rating		
	# of inverters that make up the IBR Plant Inverter		
	Output AC Voltage [V]		
Inverter Step Up Transformer (Inverter to Medium Voltage)	ISU Low voltage winding [kV]		
	ISU Low voltage winding configuration		
	ISU High voltage winding [kV]		
	ISU High voltage winding configuration		
	ISU Transformer MVA		
	Copper losses (R based on the MVA of the ISU transformer)		
	Positive Sequence Leakage Reactance (X based on the MVA of the ISU transformer)		
Equivalent Collector Branch	R [p.u.]		
	X [p.u.]		
	B [p.u.]		
	Medium Voltage AC Cable Schedule		
	Medium Voltage Cable Electrical Parameters or Data		
Main Power Transformer (Medium Voltage to POI Voltage)	MPT Low voltage winding (kV)		
	MPT Low voltage winding configuration		
	MPT High voltage winding (kV)		
	MPT High voltage winding configuration		
	Transformer MVA		
	Copper losses (R based on the MVA of the transformer)		
	Positive Sequence Leakage Reactance (X based on the MVA of the transformer)		
Gen Tie Line	R [p.u.]		
	X [p.u.]		
	B [p.u.]		
	Tie Line topology and conductor parameters		
	Tie line conductor electrical properties or parameters		
Capacitor Banks	# of banks		

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	MVAR of each bank		
	Connection bus of each bank		
	Control narrative includes the control scheme of capacitor banks		
Dynamic Voltage Control Devices	MVAR rating(s)		
	Connection bus(es)		
Aux load included (if greater than 1 MW)	MW		
	MVAR		
	Connection bus		
Protection Settings	Will the plant have AC overcurrent protection enabled?		
	If yes, is the AC overcurrent protection enabled in the PSCAD plant model?		
	Will the plant have DC protection enabled?		
	If yes, is the DC protection enabled in the PSCAD plant model?		
	Over Voltage 1: Voltage Setting [p.u.]		
	Over Voltage 1: Time Setting (sec)		
	Over Voltage 2: Voltage Setting [p.u.]		
	Over Voltage 2: Time Setting (sec)		
	Over Voltage 3: Voltage Setting [p.u.]		
	Over Voltage 3: Time Setting [sec]		
	Over Voltage 4: Voltage Setting [p.u.]		
	Over Voltage 4: Time Setting [sec]		
	Over Voltage 5: Voltage Setting [p.u.]		
	Over Voltage 5: Time Setting [sec]		
	Under Voltage 1: Voltage Setting [p.u.]		
	Under Voltage 1: Time Setting [sec]		
	Under Voltage 2: Voltage Setting [p.u.]		
	Under Voltage 2: Time Setting [sec]		
	Under Voltage 3: Voltage Setting [p.u.]		
	Under Voltage 3: Time Setting [sec]		
	Under Voltage 4: Voltage Setting [p.u.]		
Under Voltage 4: Time Setting [sec]			
Under Voltage 5: Voltage Setting [p.u.]			
Under Voltage 5: Time Setting [sec]			
Over Frequency 1: Voltage Setting [Hz]			
Over Frequency 1: Time Setting [sec]			

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	Over Frequency 2: Voltage Setting [Hz]		
	Over Frequency 2: Time Setting [sec]		
	Over Frequency 3: Voltage Setting [Hz]		
	Over Frequency 3: Time Setting [sec]		
	Over Frequency 4: Voltage Setting [Hz]		
	Over Frequency 4: Time Setting [sec]		
	Over Frequency 5: Voltage Setting [Hz]		
	Over Frequency 5: Time Setting [sec]		
	Under Frequency 1: Voltage Setting [Hz]		
	Under Frequency 1: Time Setting [sec]		
	Under Frequency 2: Voltage Setting [Hz]		
	Under Frequency 2: Time Setting [sec]		
	Under Frequency 3: Voltage Setting [Hz]		
	Under Frequency 3: Time Setting [sec]		
	Under Frequency 4: Voltage Setting [Hz]		
	Under Frequency 4: Time Setting [sec]		
	Under Frequency 5: Voltage Setting [Hz]		
	Under Frequency 5: Time Setting [sec]		

**Table 15. Model Verification Table (example)**

Item #	Equipment	Parameter	Field Value	PSS/E Model Parameter #	PSS/E Model Value	PSCAD Model Parameter Name	PSCAD Model Value	Aspen Model Value (if available)
1	PPC	Lower threshold for reactive power control	-1 Mvar	REPCA1, CONS J+12	-0.01 p.u.	PPC_Q_Thd_1	-1 Mvar	N/A
2	PPC	Higher threshold for reactive power control	1 Mvar	REPCA1, CONS J+13	0.01 p.u.	PPC_Q_Thd_2	1 Mvar	N/A
3	Inverter	LVRT level-1 protection value	0.88 pu	UDM1, CONS J+10	0.88 pu	Inv_LVRT_1	0.88 pu	N/A
4	Inverter	LVRT level-1 tripping time	100 s	UDM1, CONS J+20	100 s	Inv_LVRT_1t	100 s	N/A
5	Aggregated generator (PV panel, wind turbine, battery)	Generator maximum real power capability	100 MW	REECA1, CONS J+25	1 p.u.	Pmax	100 MW	100 MW
6	Gen-tie line	resistance (positive sequence)	0.001 p.u.	Steady state model	0.001 p.u.	R1	0.001 p.u.	0.001 p.u.

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**Table 16. Model Submittal Checklist**

Item	File Extension	Description
<b>PSS/E Standard Library Model</b>	.raw, .sav	Power flow model
	.dyr	Dynamic models
	.docx, .pdf	Model documentation (if available)*
<b>PSS/E UDM</b>	.raw, .sav	Power flow model
	.dyr	Dynamic model
	.docx, .pdf	Model documentation from all OEMs (required)*
<b>PSCAD Model</b>	.pscx	Project case file
	.pswx, .pslx, .f, .c, .obj, .lib, .dll, .par, .txt, etc.	Other files to run the case file (e.g., compiled source codes, library files, parameter files, etc.), as needed
<b>ASPEN model</b>	.orl	Short circuit model (Aspen OneLiner 15.7 or latest approved DEV version)
	.docx, .pdf	Model documentation (if available)*
<b>Model Verification Report</b>	.docx, .pdf	Report compiling all model verification defined in Section 6
<b>Model Benchmark Report</b>	.docx, .pdf	Report compiling all simulation tests defined in Section 7
<b>Model Validation report</b>	.docx, .pdf	Report compiling all model validation results defined in Section 8
<b>Additional Documents (if available)</b>	.docx, .jpeg, .png, .pdf	Supplemental files such as OEM manuals, datasheets, screenshots, pictures, OEM attestations, type test or hardware-in-the-loop (HIL) test reports, OEM contact information, etc.


\* Model documentation may include OEM-supplied user manuals, instructions for setting up and configuring the model(s), etc.

## 12.0 REVISION HISTORY

Revision Date	Revision #	Description	Revised By	Effective Date
09/10/2025	1.0	First Version	Kristen Custer	10/01/2025
3/01/2026	2.0	Second Version	Andrea Pinceti, Maxwell Danku, Thomas J. McConnell, Elevate Energy Consulting, and Danovo Energy Solutions	04/01/2026

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**Attachment 8**  
**Large Load Interconnection Requirements**  
  
**Dominion Energy Virginia—Electric Transmission**  
**Facility Interconnection Requirements**

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## Abbreviations and Acronyms

**Table 1. Abbreviations and Acronyms**

<b>Term</b>	<b>Definition</b>
<b>BES</b>	Bulk Electric System
<b>BPS</b>	Bulk Power System
<b>CMLD</b>	Composite Load Model
<b>DEV</b>	Dominion Energy Virginia
<b>DEV-ET</b>	Dominion Energy Virginia Electric Transmission
<b>NERC</b>	North American Electric Reliability Corporation
<b>OATT</b>	Open Access Transmission Tariff
<b>P</b>	Real Power
<b>PEILL</b>	Power Electronic Interface Large Loads
<b>PF</b>	Power Factor
<b>PJM</b>	PJM Interconnection
<b>POI</b>	Point of Interconnection
<b>Q</b>	Reactive Power
<b>RVC</b>	Rapid Voltage Changes
<b>THD</b>	Total Harmonic Distortion
<b>UFLS</b>	Under-Frequency Load Shedding
<b>UTC</b>	Coordinated Universal Time

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## 1.0 GENERAL REQUIREMENTS AND TIMELINE

Customers who apply for a new interconnection or change to an existing interconnection that includes Power Electronic Interface Large Loads (PEILL) are responsible for ensuring compliance with the requirements outlined in Attachment 8. If the majority of the facility load is power electronic-based, the guidance in this document is applicable. Data Centers are considered PEILL within this requirement. Customers must adhere to all applicable State jurisdictional requirements, any requirements specified by Dominion Energy Virginia (DEV), PJM Interconnection (PJM), and any Federal requirements, including, but not limited to, the NERC Reliability Standards governed by the North American Electric Reliability Corporation. This document outlines the minimum technical requirements for customers to achieve reliable and operationally efficient interconnection configurations. Nothing in this document supersedes provisions in the Open Access Transmission Tariff (OATT), current or future NERC Standards, or other DEV, PJM, and regulatory requirements.

The requirements outlined in Attachment 8 apply to Customers connecting to the DEV system exceeding 50 MW. For clarity, this includes loads connected to the low side of a dedicated load-serving substation owned and operated by DEV. Compliance with these requirements is mandatory for all Customers that request interconnection service for facilities that qualify as PEILLs. The 50 MW threshold refers to the long-term projected demand of the load, not just the initial energization demand. Additionally, DEV and PJM may classify loads below this threshold as PEILLs based on their operating characteristics, location, and proximity to other PEILLs.

DEV will conduct studies to identify required substation facilities and transmission system upgrades, evaluate compliance of the developer's initial facility design and equipment with these requirements, and potentially specify additional requirements tailored to individual sites. DEV will review the final design and equipment and evaluate performance before energization. The Customer must maintain compliance with these requirements throughout the life of the interconnection as a condition of connecting to DEV's Transmission System.

This document is intended to be used in conjunction with Dominion Energy Virginia's Facility Interconnection Requirements (FIR) and provides additional technical requirements specific to PEILL interconnections. In the event of any inconsistencies, the requirements in this document shall serve to clarify and expand upon the FIR as they relate to the unique characteristics of PEILLs.

## 2.0 FACILITY INTERCONNECTIONS AND COORDINATION


When a Customer wishes to install, make a Qualified Change to an existing Interconnection, or remove DEV-ET Facilities at a Delivery Point or point of interconnection (POI), the Customer must initiate the request in writing using the Customer Request Form in Attachment 2 of the FIR. Note that the Customer must submit a Customer Request Form to DEV-ET when making Qualified Changes to the Customer's Facilities that are anticipated to (i) lead to a modification to DEV-ET's Facilities (ii) impact the operation of DEV-ET's Facilities, or (iii) Change the primary type of load (for example, from general data processing to AI processing or cryptocurrency mining) in a way that could alter load characteristics.

### 2.1 Wholesale Delivery Points

The Interconnection Customer shall refer to DEV-ET's FIR, Section 1.4 and Section 2.2.

### 2.2 Required Simulation Data

The Customer shall adhere to DEV-ET's FIR, Section 2.1, and Attachment 2, Customer Request form. DEV-ET requires Customers to provide detailed modeling information necessary to support system studies at various

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stages, including planning, integration, and ongoing operations. All Customers must provide a composite load model (CMLD), EV Load Model, or other user-defined model representing load facility dynamics in PSSE format.

The Customer shall provide, through Attachment 2, site-specific load data that accurately represents the proposed PEILL, including, but not limited to, load composition, ride-through capability, load profile characteristics, backup power system details, protection system, and reconnection behavior after a grid disturbance. Insufficient or inaccurate modeling information, including updates resulting from equipment changes, can significantly affect the timeline for placing a PEILL in service.

The Customer must provide as-planned and as-built load information to DEV-ET. DEV-ET will review each set of load information submitted. Meaningful discrepancies that impact system reliability may affect the timeline for placing a Customer in service or could necessitate a temporary reduction or disconnection from the DEV transmission system based on operational requirements.

- As-planned Load Information
  - The as-planned load information must reflect the proposed equipment, configuration, performance, and protection settings specific to the PEILL.
- As-built Load Information
  - The as-built load information must accurately reflect the installed equipment, configuration, performance, and protection settings.

Prior to the initial energization, DEV-ET might perform simulations using the as-planned and as-built load models to verify compliance with the performance requirements outlined in this document. If these simulations indicate non-compliance, the Customer must:

- Propose a solution addressing the identified deficiencies.
- Provide updated load information reflecting the proposed solution.
- Allow DEV-ET to verify through simulation that the solution resolves deficiencies without negatively impacting other performance requirements.
- Provide evidence of solution implementation.

### **2.3 Transformer Winding Configuration**


If the Customer owns the transformer(s) interconnecting with the transmission system, the proposed transformer winding configuration must be submitted to DEV-ET for review and approval. To support this review, the Customer shall inform DEV of any current or planned Customer-owned generation that will operate in parallel (i.e., synchronized) with the transmission system.

Unless otherwise approved, the high-voltage (utility-side) winding of the Customer-owned transformers shall be configured as delta to ensure compatibility with DEV’s protection, grounding, and operational standards.

### **2.4 System Protection and Coordination**

The Interconnection Customer shall adhere to DEV-ET’s FIR, Sections 2.3 and 2.4.

Participation in system-wide Under-Frequency Load Shedding (UFLS) programs is a requirement for all applicable Customers. Facilities subject to UFLS must be equipped with appropriate protection relays and communication infrastructure to ensure the timely and coordinated disconnection of load during low-frequency events. It is the responsibility of the interconnecting entity to ensure that UFLS capabilities are implemented following DEV-ET technical requirements.

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## 2.5 Metering and Telecommunications

The Interconnection Customer shall adhere to DEV-ET’s FIR, Sections 2.3 and 2.4.

In addition to standard revenue metering equipment required for billing and operational data, each customer facility shall install dedicated, industry-compliant power quality meters at the POI. These power quality meters must provide continuous monitoring and recording of detailed electrical parameters essential for ensuring system reliability and operational efficiency. Specifically, the meters shall measure and record the following data at high resolution:

- Real power (P), reactive power (Q), and power factor (PF): Time-synchronized logging of power and power factor value to track fluctuations or ramping behavior.
- Energy Usage: Cumulative kWh and kVARh by phase and total
- Voltage and current harmonics: Individual harmonics from the fundamental frequency up to the 50th harmonic, as well as total harmonic distortion (THD) for both voltage and current.
- Voltage flicker: Short-term flicker severity (Pst) and long-term flicker severity (Plt), compliant with IEEE Std 1453.
- Rapid Voltage Changes (RVC): Magnitude, frequency, and duration of voltage dips, swells, and other rapid transient voltage events.
- Voltage and current imbalance: Detailed measurements of unbalanced conditions across all phases.
- Transient disturbances: High-resolution capture of transient voltage and current waveforms resulting from switching events, faults, or equipment operations.
- Frequency deviations: Real-time recording of system frequency variations, including frequency ride-through events.

All recorded power quality data shall be accurately timestamped to Coordinated Universal Time (UTC), ensuring precise event correlation and ease of system-wide analysis. The recorded data shall be securely stored for a minimum retention period of 90 days.

Installation, maintenance, and operation of these power quality meters must comply with industry-recognized standards and guidelines, including IEEE 519 (harmonic distortion limits), IEEE 1159 (monitoring of electric power quality), IEEE 1453 (flicker), and IEC 61000 series standards (general power quality measurement and testing standards). The Customer shall be responsible for routine testing, calibration, and maintenance of the power quality meters, ensuring continuous accuracy and reliability of recorded data throughout the operational life of the interconnection.

There are scenarios in which installing a monitoring device solely on the data center feeder does not meet the requirements for accurate metering. The following outlines three such cases and specifies the appropriate placement of the required monitoring device(s).

2.5.1 Example 1

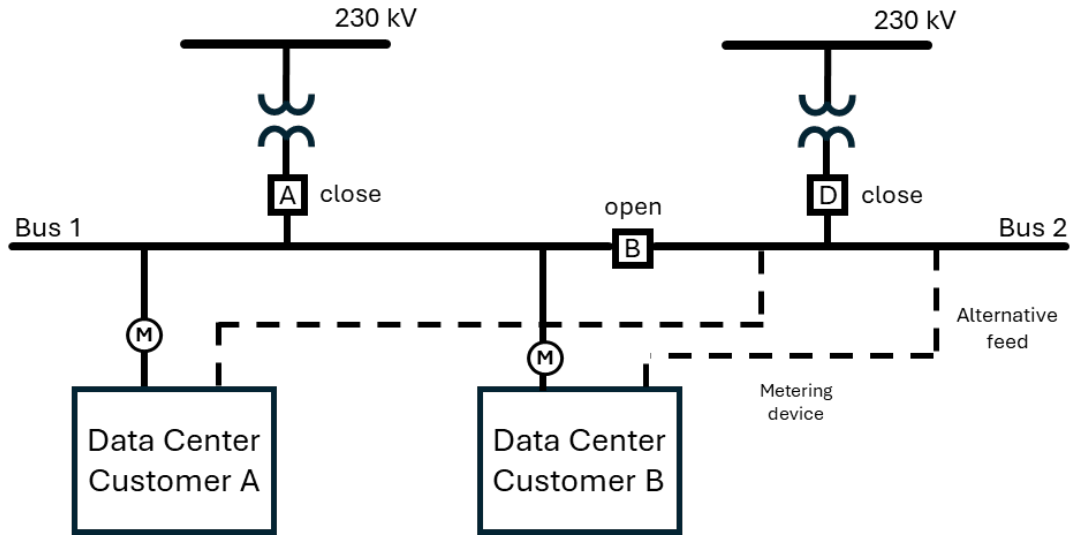


Figure 1. Two data centers with monitoring on their primary feeds (Circuit Breaker A closed)

Figure 1 illustrates a configuration where two data center customers are supplied through Bus 1 and Bus 2. Solid lines represent the primary feeds, while dashed lines indicate the alternate feeds. As shown, both data centers are primarily fed via Bus 1. The monitoring devices are located at the primary feeders, covering the power usage of the data centers during normal operation.

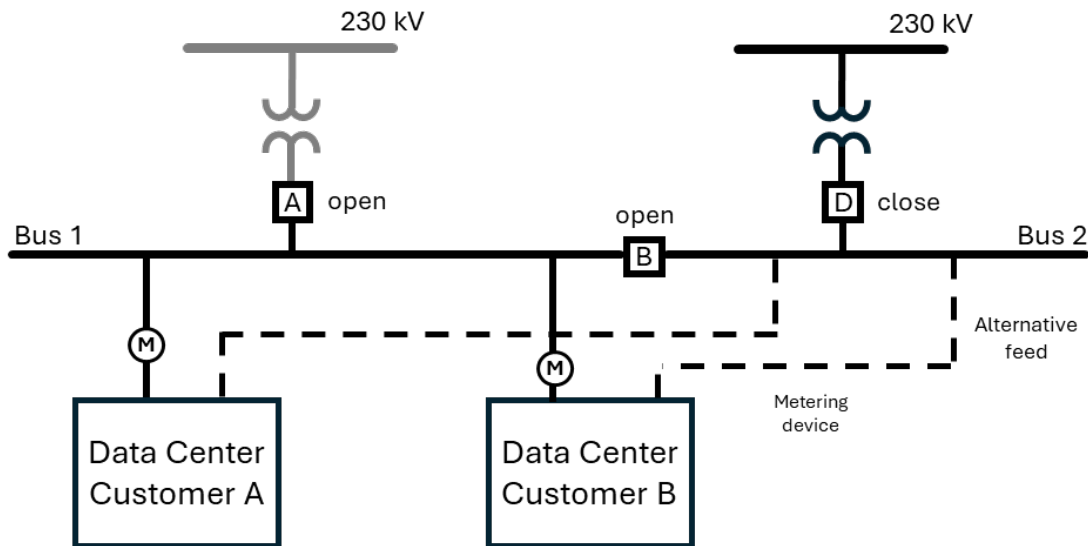
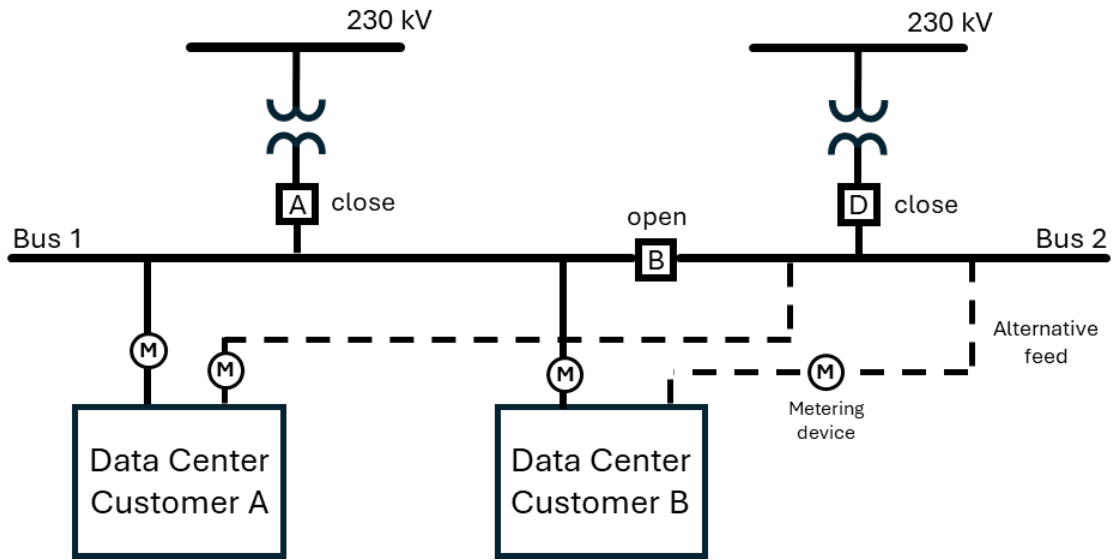


Figure 2. Two data centers with monitoring on their primary feeds (Circuit Breaker A: open)

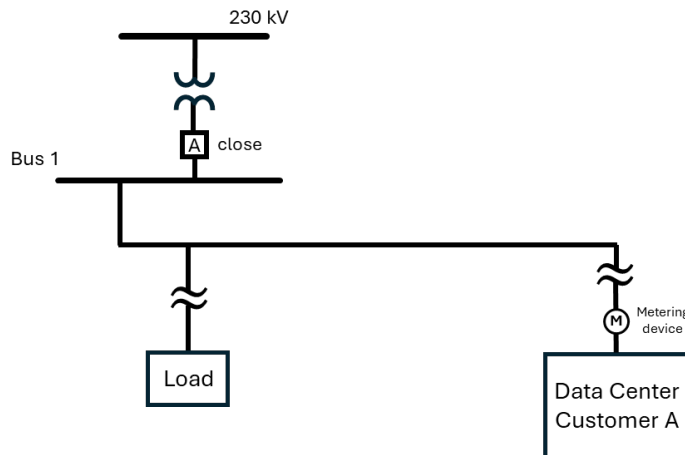
However, if due to a fault in the system, the data centers may feed from Bus 2. Figure 2 shows a situation where Bus 1's source is disconnected, and the data centers are fed through their alternative feeds. If the monitoring is placed only on the primary feeders, the power usage of data centers cannot be measured in the mentioned scenario.



**Figure 3. Two data centers with monitoring on both their primary and alternative feeders (required placement of monitoring devices)**

To ensure accurate measurement for all topologies, both primary and alternative feeders need to be monitored, as shown in Figure 3.

### 2.5.2 Example 2



**Figure 4. A data center and a load fed through a common feeder**

The topology in Figure 4 illustrates the recommended placement of the monitoring device when a data center and other loads share the same feeder. If the monitoring device is installed at the bus level, the data center’s specific load cannot be measured accurately. Positioning the monitoring device on the feeder at the data center end ensures precise load tracking.

### 2.5.3 Example 3

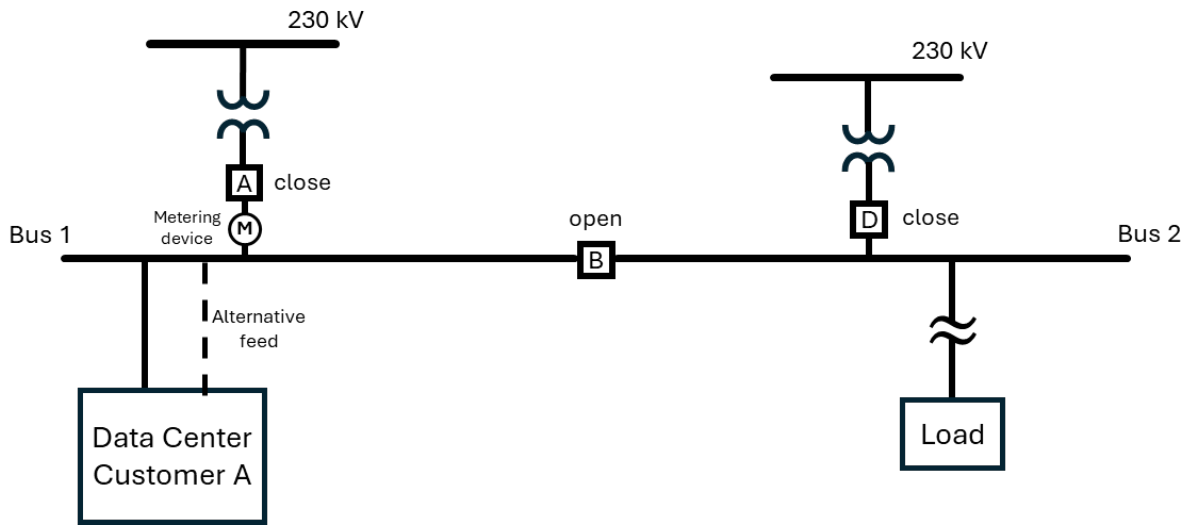


Figure 5. Metering device after Circuit Breaker A closed, Circuit Breaker B open, and Circuit Breaker D closed

Figure 5 illustrates a scenario where one data center and another load are fed through individual buses, with each bus serving only one data center. In Figure 6, placing the monitoring device after the transformer circuit breaker provides accurate data center load measurement whether the primary or alternate feed is being used.

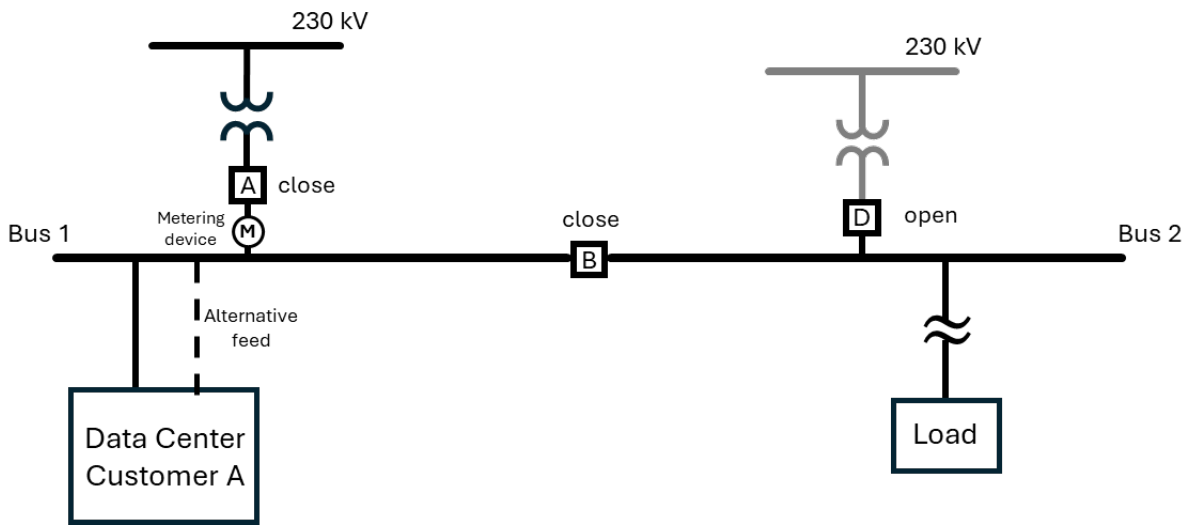
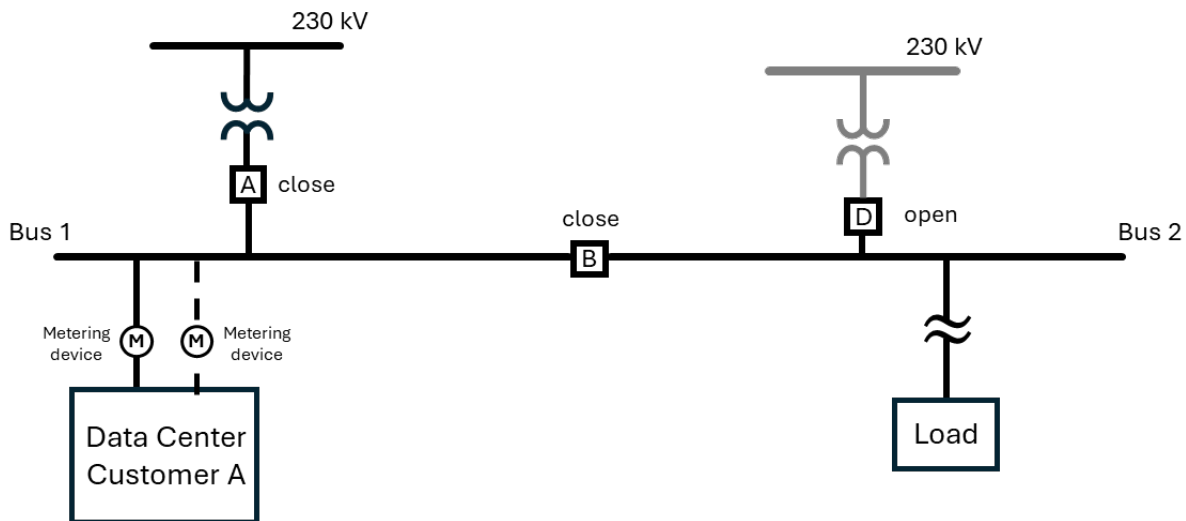


Figure 6. Metering device after Circuit Breaker A, Circuit Breaker B closed, and Circuit Breaker D open

However, if one of the 230 kV buses loses power, the situation will change. For example, if Circuit Breaker D at Bus 2 opens due to a fault, and Circuit Breaker B closes to maintain service, the load on Bus 2 remains energized (Figure 6). In this case, the monitoring device would record the combined load of the data center and other customers.



**Figure 7. Metering device at the data center, Circuit Breaker D open, and Circuit Breaker B closed (required placement of monitoring devices)**

To address this, it is required to locate the monitoring devices as shown in Figure 7 to ensure accurate megawatt measurements for the data center, even under the above-mentioned contingency.

## 2.6 Interconnections

The Interconnection Customer shall adhere to DEV-ET’s FIR, Sections 2.13, 2.14, and 2.15.


To preserve system integrity and ensure reliable protection coordination, Dominion Energy Virginia (DEV-ET) requires Customers to follow strict guidelines when implementing redundancy schemes, inter-substation connectivity, and shared transformer arrangements.

Load transfer between two or more transmission sources or feeders within the distribution network is prohibited.

## 2.7 Control System Stability and Equipment Interaction

The Customer facility must be designed and operated to prevent any adverse or unstable interactions with the DEV-ET transmission network or the control systems of other interconnected facilities, such as generators, FACTS devices, neighboring IBRs, or other PEILLs. The Customer shall collaborate actively with DEV-ET to promptly investigate, identify, and address any actual or potential stability concerns or adverse control interactions. To support detailed system studies, DEV-ET may request models in PSCAD format.

If DEV-ET determines during normal operation or through detailed system studies that the Customer facility is significantly contributing to detrimental interactions or control system instabilities, DEV-ET reserves the right

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to require the PEILL to temporarily reduce its load or disconnect entirely from the transmission network to maintain overall system reliability and stability.

### **2.8 Co-location and On-Site Generation Requirements**

For Customer facilities planning to incorporate co-located or on-site generation, the Interconnection Customer shall explicitly indicate such arrangements during the initial interconnection application process, through the Customer Request Form. Co-located generation facilities must adhere to all applicable DEV-ET and PJM interconnection requirements, including revenue and operational metering, telemetry, protection and control coordination, and power quality standards. The Interconnection Customer shall adhere to DEV-ET's FIR, Section 2.12 and 3.2.

The Interconnection Customer must clearly distinguish generation from load through separate metering and telemetry systems. For facilities that include load behind the POI, such load must be configured in a radial arrangement to remain non-Bulk Electric System (non-BES). Networked configurations between multiple BES connections are prohibited, even when such connections are intended for redundancy.

For facilities with cogeneration or on-site generation, the Interconnection Customer shall not increase the net load at the POI above the level specified in the approved interconnection agreement if generation output decreases or goes offline.

DEV-ET will require detailed modeling data representing both load and generation components independently. Additional power quality metering and telecommunications may be required for facilities with on-site generation to ensure accurate compliance monitoring and reliable system operation. Specific metering and telemetry arrangements will be determined by DEV-ET on a case-by-case basis, considering factors such as facility configuration, market participation, and the impact on operational reliability.

## **3.0 CAPABILITY AND PERFORMANCE**


This section details the capability and performance requirements.

### **3.1 Power Factor Requirements**

The Customer shall provide DEV-ET with detailed expected power factor characteristics aggregated at the POI for various loading conditions, clearly specifying whether the load is anticipated to operate with a lagging or leading power factor. All information must be submitted through Attachment 2, Customer Request Form. DEV-ET will evaluate whether the existing transmission system can reliably support the power factor characteristics provided by the Customer. Based on this evaluation, DEV-ET may require the installation of additional equipment by the Customer to manage and correct the power factor, thus mitigating potential reliability and operational issues.

For load, the Interconnection Customer shall design and operate the facility such that the aggregate power factor at the POI is maintained near unity during normal operation, with a minimum acceptable power factor of 0.95 (lagging or leading).

Moreover, the Customer facility is expected to operate consistently within the power factor range coordinated and agreed upon with DEV-ET, as transmission system planning and reliability assessments depend upon these assumptions. Should the Customer Facility deviate significantly from the coordinated power factor, causing reliability or operational concerns, DEV-ET may require the Customer owner to (1) install additional equipment to correct the power factor deviation, and/or (2) temporarily reduce or disconnect the Customer

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Facility from the DEV-ET transmission system as necessary to maintain system reliability and operational stability.

### 3.2 Oscillations

Certain PEILLs, particularly those embedding constant power loads with variable or cyclical load profiles such as data centers, have the potential to introduce forced oscillations into the Bulk Power System (BPS). Consequently, PEILL facilities must be designed and operated to minimize any significant signal injections into the transmission system within the following critical frequency bands: 0.01 – 0.5 Hz: Eastern Interconnection inter-area oscillation modes, 0.5 – 0.8 Hz: Sub-regional area oscillation modes, 0.8 – 2 Hz: Local oscillation modes, and 5 – 55 Hz: Sub-synchronous oscillation modes.

In certain circumstances, DEV-ET may also specify additional frequencies or narrower bands of concern based on site-specific analyses. The Customer must provide DEV-ET with its detailed expected load profile, clearly depicting active and reactive power variations, to enable thorough evaluation of cyclic or periodic behaviors. DEV-ET may require the Customer to implement mitigation measures or install specialized equipment to minimize potential signal injections within the frequency ranges identified.

Monitoring equipment capable of supporting wide-area oscillation detections might be installed at the POI, unless DEV-ET determines that such equipment is not required based on the specific characteristics of the facility and its impact on the transmission system. Should DEV-ET identify that the Customer is significantly contributing to harmful oscillations on the transmission system, DEV-ET reserves the right to require the Customer to (1) install additional mitigation equipment targeting the specific impactful modes, and/or (2) temporarily reduce or disconnect from the DEV-ET transmission system to maintain overall system reliability and stability.

### 3.3 Ride-through Requirements


Customer interconnection requests associated with PEILLs require close department-level coordination within DEV-ET Planning and Operations to ensure system reliability and operational stability. To mitigate risks associated with large load loss during disturbances, large data center Customers must ensure their protection system designs account for voltage stability and ride-through capability. In particular, the Customer must demonstrate the ability to reliably ride through standard transmission system disturbances without disconnecting from the grid. The primary objective of these ride-through requirements is to ensure continuity of service and maintain overall system reliability, particularly during typical system operations such as automatic reclosing schemes following transient faults.

Specifically, PEILLs shall be designed and operated to remain connected through a series of automatic reclosing events. At a minimum, PEILLs must demonstrate the capability to ride through at least six automatic reclosing attempts that last 50-70 milliseconds each, aligned with DEV-ET's typical operational practices. Customers should review the NERC Incident Review on Large Load Loss<sup>1</sup> for illustrations of the type of typical transmission system disturbance that PEILLs are expected to ride through. This event highlights the importance of designing load-side protection and control schemes to maintain connectivity during standard reclosing sequences and transient voltage depressions.

To help meet the ride-through requirement of withstanding six short voltage depressions caused by breaker reclosing attempts, DEV-ET recommends reviewing and, where appropriate, increasing the short-duration

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<sup>1</sup> NERC Incident Review, "Considering Simultaneous Voltage-Sensitive Load Reductions", January 8<sup>th</sup>, 2025.

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voltage depression event detection timer to approximately 80–120 milliseconds or more. Breaker operations during a reclosing attempt typically occur within 50–70 milliseconds, so setting the timer above this window reduces the likelihood that normal reclosing operations will be misinterpreted as a triggering event. When setting up this timer, Customers should consider the measurement tolerances of voltage detection devices. Additionally, lower undervoltage pickup settings further reduce the likelihood of transferring load during standard system events. These recommendations aim to enhance ride-through performance and enable Customers to reliably meet the six-event requirement.

Protection settings must be coordinated with DEV-ET Planning and Operations through the assigned Customer account point of contact to avoid premature load shedding and ensure compliance with reliability criteria.

### 3.4 Power Quality

The Interconnection Customer shall adhere to DEV-ET’s FIR, Section 2.9. Additionally, at no time shall instantaneous voltage fluctuations caused by the Customer exceed 3% to avoid negatively impacting service quality to adjacent Customers.

## 4.0 REFERENCES

## 5.0 REVISION HISTORY

Revision Date	Revision #	Description	Revised By	Effective Date
09/10/2025	1.0	First Version	Kristen Custer & Quanta Technology	10/01/2025
03/01/2026	2.0	Second Version	Narges Ghiasi, Nate Rice, Katelynn Vance, Thomas McConnell, and Danovo Energy Solutions	04/01/2026