

*Technical Interconnection Requirements and Study Criteria for Distributed Energy Resources Interconnected to Distribution Systems*

*February 2023*

**1. Purpose**

- 1.1. The purpose of this document is to define the FirstEnergy distribution operating company (Company) technical requirements for distributed energy resource (DER) interconnection with the distribution system.
- 1.2. Additionally, this document informs potential DER interconnection customers about the process and evaluation criteria used to review and study interconnection applications by The Company. This informative section is provided in Appendix A.
- 1.3. The technical requirements and study criteria identified in this document are to ensure the safety of Company employees and the public, to protect Company equipment from damage and to ensure the reliability of service to Company customers.

**2. Applicability**

- 2.1. The requirements of this document are applicable to all types of DER interconnection with the distribution system and should be applied for customers intending to participate in state retail net metering connections, connections as qualified facilities under PURPA, and connections participating in the PJM wholesale market. These technical requirements should also be applied to storage systems designed to operate in parallel (synchronized) with the distribution system.
- 2.2. Customers utilizing power producing resources that do not operate in parallel with the area EPS, such as emergency back-up generation, or storage batteries used only for back-up purposes, are not subject to the requirements of this document. However, their installation should meet the requirements of the NEC. Transfer switches or other methods that assure separation of the Company area EPS from the Customer owned local EPS must be utilized. Permits, inspections, and approvals by the authority having jurisdiction should be obtained for electrical system modifications related to back-up power systems as described and defined in the NEC.

**3. Definitions**

- 3.1. Terms and acronyms used in this document are to be interpreted as defined in section 3 of IEEE Std 1547-2018. The reader is advised to reference the standard since it is integral to understanding the requirements of this document.

**4. Design Requirements – Certified Inverter-Based or Certified other DER**

- 4.1. It is the policy of The Company to require that all customer DER interconnection conform with the requirements of IEEE Std 1547-2003, as amended by IEEE Std 1547a-2014, at a minimum. To the extent that it is reasonable to do so, regional engineering will require that DER installations conform with IEEE Std 1547-2018. The Company will continue to evaluate regulations and developments regarding the availability of certified inverters to determine the effective date for full compliance with IEEE Std 1547-2018. While the transition to full compliance takes place, The Company has adopted the interim inverter equipment requirements described as follows:
- 4.2. The Customer’s design, installation and operation should meet the requirements of IEEE 1547-2018, except as noted in the following paragraph 4.3.
- 4.3. The Customer DER should utilize equipment that is UL 1741 / UL1741SA certified as a “Grid Support Interactive Inverter”, or a “Grid Support Utility Interactive Inverter” utilizing IEEE 1547-2003, or IEEE 1547a-2014 compliant settings with all grid support functions disabled (See Table 1).

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<b>Table 1 - Interim Inverter Equipment Requirements</b>			
<b>Function (1547-2018 Term**)</b>	<b>UL 1741 SA Term and Section</b>	<b>SA Testing Required</b>	<b>Function Enabled?</b>
Low/High Voltage Ride-Through	Low/High Voltage Ride-through, SA9	Yes	N/A
Low/High Frequency Ride-Through	Low/High Frequency Ride-through, SA10	Yes	N/A
Enter Service Ramp Rate	Soft-Start Ramp Rate, SA11	Yes	N/A
Constant Power Factor Mode	Specified Power Factor, SA12	Yes	No
Voltage-Reactive Power Mode	Volt-Var SA13	Yes	No
Frequency-Droop Operation	Frequency-Watt, SA14	Yes	No
Voltage-Active Power Mode	Volt-Watt, SA15	Yes	No
<p><i>Table Notes:</i></p> <p>* UL 1741SA testing requires testing to IEEE 1547.1-2005 or IEEE 1547.1a-2015. The grid support functionality testing contained in UL 1741SA will be incorporated in IEEE 1547.1 and referenced by UL 1741 once revised and published. Once published, the revised IEEE 1547.1 may be used in lieu of UL 1741SA.</p> <p>** Not all IEEE 1547-2018 functions are included in this table</p> <p>Note 1: Power Factor should be set = 1.0</p> <p>Note 2: The Company intends to change the requirements of paragraph 4.3 when equipment type-tested and certified to the latest version of IEEE 1547.1 become available (Estimated timeframe – June, 2022).</p>			

- 4.4. A DER System should be considered certified as complying with the above-referenced standards if it has been submitted by a manufacturer to a nationally recognized testing and certification laboratory and has been tested and listed by the laboratory for continuous interactive operation with an area EPS in compliance with the standards listed above.
- 4.5. The DER should provide appropriate protection and control equipment, including an interrupting device(s) that will automatically disconnect the DER from the area EPS in the event the area EPS becomes de-energized or for a fault on the

local/area EPS. The automatic interrupting device(s) should be either inverters, certified as described in 4.3, or circuit breakers (including reclosers) with protective relays approved by the Company. (See section 4.11) Unless specifically required by and approved by the Company in writing, the settings for automatic operation should conform to the following Table 2 - Company Voltage and Frequency Settings Requirements (See section 4.11 for relays performing a back-up function). No setting should be changed by the Customer after initial commissioning unless specifically authorized by the Company in writing.

<b>Table 2 - Company Voltage and Frequency Settings Requirements</b>			
Voltage Range (% of base)	Cease to Provide Real Power or Clearing Time (s)	Frequency (Hz)	Ceased to Provide Real Power or Clearing Time (s)
$V < 45$	0.16	$< 57$	0.16
$45 \leq V < 60$	1.0	$< 59.5$	2.0
$60 \leq V < 88$	2.0		
$110 < V < 120$	1.0	$> 60.5$	2.0
$V \geq 120$	0.16	$> 62$	0.16

- 4.6. Following a disconnect of the DER due to voltage or frequency excursion, the DER facility should remain disconnected until the area EPS has recovered to acceptable voltage and frequency limits for a minimum of five minutes. The Customer is solely responsible for the protection of its equipment from automatic reclosing by the Utility. The Company normally applies automatic reclosing to overhead electric distribution circuits. When the Company protective device trips, the Customer must ensure that its DER is disconnected from the Company area EPS prior to automatic reclosing. The automatic reclosing on Company distribution feeders is normally delayed by at least 2 seconds. Automatic reclosing out-of-sync with Customer’s DER may cause severe damage to Customer equipment and could also pose a serious hazard to Customer or Utility personnel.
- 4.7. In the case of a Customer owned relay trip, a qualified person should assess the reason for the trip and determine if the conditions that caused the trip have cleared. If the area EPS has returned to normal, the relay may be reset and normal DER operation may be restored (See section 4.11).

- 4.8. Customers who are connected via SCADA with the Company Distribution Control Center (DCC), should contact the DCC and obtain permission from the distribution system operator to reset the DER protection equipment and return to normal operation. (See section 7.1)
- 4.9. All DER connecting behind a 3 phase PCC, should be capable of being isolated from the utility system by means of a manual, visible open, lockable, load break disconnect switch conforming with the NEC. The switch should be installed outdoors in the immediate vicinity of the electric meter, or service entrance to facilitate access by Company personnel. The switch should be clearly marked, "Generator Disconnect Switch," with permanent 3/8 inch or larger letters.
- 4.10. In unique circumstances, locating the disconnect switch outdoors may not be practical. In such cases, the Customer may request the Company to approve the location of the switch to be inside the designated Electric Room where it should be readily accessible for operation and locking by utility personnel. In some cases, a circuit breaker capable of being racked out and locked by Company personnel may be acceptable. Whenever the Company approves an indoor disconnect switch location, the Customer should provide a permanent sign, of a type approved by the Company, mounted on the building near the electric service entrance that reads, "Customer Owned Generation – Disconnect Switch Inside". Posting of specific directions and/or a lockbox may also be required to locate and access the switch.
- 4.11. Customer inverter-based DER interconnections rated 300kW (aggregate inverter nameplate rating), or larger, should utilize microprocessor based multi-function relay protection (SEL 751 relay, or approved equivalent), and a controlled switch capable of interrupting the available fault current (circuit breaker, recloser, etc.) as supplemental DER devices to meet the requirements of IEEE-1547. Smaller DER may require a similar level of protection and control depending on the specific configuration of the local and area EPS. Voltage and current sensing instrument transformers should be installed as close as practical to the PCC, however, a controlled switch may be installed in a location that will only trip the DER and not customer load (Reference Figure 2 and 3). Relays, circuit breakers, and reclosers should comply with the most current version of the following standards:
- Relays
    - ANSI/IEEE C37.90-1989 (R1994), IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus.

- ANSI/IEEE C37.9.01-1989 (R1994), IEEE Standard Surge Withstand (SWC) Tests for Protective Relays and Relay Systems.
  - ANSI/IEEE C37.90.2-1995, IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers.
  - Circuit Breakers
    - IEEE C37.13.1-2016, IEEE Standard for Definite-Purpose Switching Devices for use in Metal-Enclosed Low-Voltage Power Circuit Breaker Switchgear
    - IEC 62271-100, IEC standard for High-Voltage Switchgear and Control Gear
  - Reclosers
    - IEEE/IEC 62271-111, ANSI C37.60, 2012
- 4.12. The Customer should submit all relevant relay protection settings along with a single line drawing to the Company for review and approval. The relay device functions listed in Table 3 - Protective Relay Elements are to be considered by the Customer when designing their protection settings. For relay device functions listed as “back-up” in Table 3 - Protective Relay Elements, the Customer should select settings that properly coordinate with the inverter(s) base settings. Back-up relay functions are not required to meet the total clearing time requirements of Table 2 - Company Voltage and Frequency Settings Requirements. The Customer should specifically consider how to assure that the relay protection and control system will trip the DER upon disconnection of a single phase of the area EPS within 2 seconds.

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<b>Table 3 - Protective Relay Elements</b>			
ANSI Device Number	Function	Recommended Purpose	Back-Up Function
27P	Phase Undervoltage	Back-up Undervoltage	Yes
59P	Phase Overvoltage	Back-up Overvoltage	Yes
81O	Over Frequency	Back-up Over Frequency	Yes
81U	Under Frequency	Back-up Under Frequency	Yes
59Q	Negative-Sequence Overvoltage	Primary Open Phase Detection	No
51Q	Negative-Sequence Time Overcurrent	Primary Open Phase Detection	No
59G	Zero-Sequence Phase Overvoltage	Primary Ground Fault Detection	No

- 4.13. The Customer should provide an Uninterruptable Power Supply (UPS) to power the protective device and relay(s) should the normal power source fail. The UPS should be capable of supplying back-up power for a minimum of 1 hour.
- 4.14. The Customer should make every effort to maintain an equal balance of power import, or export on all three electrical phases as measured at the PoC of each inverter. All Customer locations served by the Company with three-phase electrical service should utilize three-phase inverters providing equal power flow on each phase, or if using single-phase inverters, demonstrate how the phase balance will be maintained in the application documents.
- 4.15. DER connected to an area network system should not cause tripping of network protectors due to reversal of power flow.

**5. Design Requirements – Non-Certified DER**

- 5.1. This section addresses DER that are synchronous or induction generators without certification to UL1741. These “non-certified DER” should meet all requirements of IEEE Std 1547-2018 and utilize Category I for disturbance ride-through requirements and Category A for voltage regulation performance and reactive power capability requirements. Due to synchronous and induction generation not being certified under UL1741, it is anticipated that synchronous and induction generators will utilize utility grade relays and external protective devices to meet the requirements of this document and IEEE Std 1547-2018. Reference Figures 5 and 6 at the end of this document for typical single-line



drawings for rotating generators. The non-certified DER owner is responsible for providing adequate protection to Company facilities for conditions arising from the operation of DER under all Company distribution system operating conditions. The DER owner is also responsible for providing adequate protection to their facility under any distribution system operating condition, including when the DER is not synchronized to the area EPS. Conditions may include but are not limited to:

- Loss of a single phase of supply
- Distribution system faults
- Equipment failures
- Abnormal voltage or frequency
- Lightning and switching surges
- Excessive harmonic current injection
- Excessive negative sequence voltages
- Separation from supply
- Synchronizing generator to the distribution system
- Re-synchronizing the generation after electric restoration of the supply.

- 5.2. Utility grade relays meeting the requirements of 4.11 should be used to meet the protection requirements for non-certified DER.
- 5.3. For non-certified DER that can contribute more than 5% of the available fault current at the PCC, or where the generation can deliver energy or fault current on to the substation high-side bus to which it is connected, the design of the isolation and fault protection should be based upon a single failure philosophy, i.e., the failure of any single component (primarily relays or stuck breaker protection) should not render the protection inoperative. Regional Distribution Planning & Protection should determine the adequacy of the proposed protection scheme.
- 5.4. Where relays are required to meet the DER protection requirements of this document and IEEE Std 1547-2018, the relay(s) must trip the DER primary interrupting device directly, without relying on the operation of other equipment to cause the interruption.

- 5.5. Non-certified DER protection and controls must be designed to coordinate with the reclosing practices of Company line protective devices. The non-certified DER must cease to energize the Company circuit to which it is connected prior to automatic re-closure of any of The Company's automatic reclosing devices.
- 5.6. The non-certified DER should cease to energize The Company distribution system for faults on the circuit to which it is connected. The non-certified DER should not reconnect to the system following a trip from a local or area EPS protection device until the system has been re-energized for a period of five minutes.
- 5.7. The non-certified DER protection and controls should be designed to prevent the DER from being connected to a de-energized FirstEnergy circuit. The DER must connect to the FirstEnergy system through an interrupting device, which has adequate fault interruption, and withstand capability, and adequate continuous current and voltage rating in accordance with latest IEEE C37 standards (see section 4.11) at the time its commissioned. Three-phase non-certified DER should use an interrupting device that interrupts all three phases simultaneously. The tripping control of the circuit-interrupting device should be powered independently of the utility AC source in order to permit operation upon loss of the FirstEnergy supply.
- 5.8. The non-certified DER should not be a source of excessive harmonic voltage and current distortion and/or voltage flicker. Non-certified DER should meet the requirements of IEEE 1547-2018, Section 7.
- 5.9. When required by The Company, the non-certified DER should be capable of maintaining a fixed or variable power factor between 0.95 leading and 0.85 lagging (injecting or absorbing VARs) as measured at the POI or at the PCC as determined by The Company.
- 5.10. A non-certified DER connected to an area network system should not cause tripping of network protectors due to reversal of power flow.
- 5.11. The non-certified DER protection and controls must be able to detect an island condition on one or more phases and disconnect all phases of the generator from the FirstEnergy system within two seconds of the formation of an island on any phase. The anti-islanding requirement can be satisfied by using any of the following methods, subject to the approval of FirstEnergy:
  - Direct Transfer Trip (DTT) with Company protective devices

- Use of over and under voltage and frequency relays where the remaining load on the line section the generator is connected to is significantly larger (3 times or greater) than the aggregate generation rated capacity on that line section after operation of a Company protective device.
  - Reverse power relaying provided at the PCC and set for a minimal power import consistent with the current transformer sensitivity.
- 5.12. The Customer should submit all proposed relay settings to The Company for review prior to commencement of commissioning activities.

**6. Direct Transfer trip (DTT) – Certified and Non-certified DER**

- 6.1. The Company will make the determination if a DTT scheme is required on a case-by-case basis. A DTT scheme will typically be required when the total aggregate DER connected to the distribution system is capable of injecting fault current flow onto the transmission system, or if both of the following are true:
- The DER is any of the following types; a synchronous machine, a non-certified inverter, a certified inverter capable of and configured to operate in standalone mode, a certified inverter operating in any configuration whereby the anti-islanding function is disabled or a self-excited induction generator, any of which are capable of sustaining a load when separated from the system, and
  - The minimum load on the islanded line section connected to the DER following the opening of any automatic sectionalizing devices is not greater than 3 times the aggregate DER capacity.

Note: Where existing substation and line protective devices exist, that cannot be configured to send DTT signals (i.e., legacy breaker/recloser controls, hydraulic reclosers, sectionalizers, and fuses) these devices may need to be replaced with equipment that is capable of sourcing DTT signals at the Customer's expense.

- 6.2. The DTT scheme design, equipment, and type of communication channel should be proposed by the generator owner and submitted to The Company for review and acceptance.
- 6.3. The DTT scheme must be designed to automatically trip and separate the generator from the Company distribution system within 2 seconds upon loss of communication channel. The generator should not reconnect to the system until the communication channel is proven to be functioning normally for a period of five minutes.

- 6.4. Responsibilities for purchase, installation, and ownership of DTT equipment will be as follows:
1. The generator owner should own and provide a direct-transfer trip receiver(s) at their facility to receive tripping signals originating from a Company location(s).
  2. The DER owner will be responsible for the costs to purchase and install the required DTT transmitting and associated relaying equipment at the required Company location(s). The Customer will perform or coordinate the installation of the equipment at the cost of the Customer. The Customer will own and be responsible to maintain and perform periodic maintenance and testing of DTT equipment.
  3. Where the trip signal originates inside a Company substation, The Company will be responsible for trenching, conduit and cable installation to the Customer's communication transmitting equipment location, at the expense of the Customer. This equipment will generally be located outside the substation fence. The connection between Company substation equipment and the Customer's equipment should be fiber or otherwise isolated to ease electric potential difference concerns under fault conditions.
  4. The Customer is responsible for the design, installation, and maintenance of a dedicated, point-to-point communication channel(s) between The Company location(s) and the Customer's facility, including any rental, license, and attachment fees for the communications equipment and channel.
  5. When DTT equipment needs replacement due to age or continued unreliable performance, the Customer is responsible for purchase and installation costs of the new equipment.
  6. The Customer should apply for electric service to power DTT equipment located adjacent to Company substations.
- 6.5. If the Customer desires to install communications cables or equipment on Company poles, The Customer will be responsible to secure a license agreement or pole attachment agreement for those attachments and assume typical licensed attachment responsibilities in terms of make-ready work costs and annual attachment fees. Cable attachment will be in the communications space on the poles

- 6.6. When a DTT tripping signal originates from a Company substation breaker, the preferred location for DTT transmitter and associated equipment is outside The Company substation in an approved outdoor enclosure.
- 6.7. The Company will establish a demarcation point for any DTT communication cables leaving the substation property. The Company will perform or coordinate the installation of the cable and conduit up to the demarcation point including the box enclosure. The Company will determine the enclosure location. All material and installation costs will be the responsibility of the Customer. The Customer will be responsible to install cable and conduit originating from their end up to the demarcation point. Details of the planned installation including any trenching must be approved by The Company.
- 6.8. The generator owner may be responsible to compensate The Company for any labor expenses involved with troubleshooting or testing of the DTT communications or protection system.

## **7. Communications and Control – Certified and Non-Certified DER**

- 7.1. In general, Customer DER interconnections rated 1000 KW (total inverter nameplate rating), or larger, should provide The Company with access to their Supervisory Control and Data Acquisition (SCADA) system via a Remote Terminal Unit (RTU) and a dedicated communications circuit approved by the Company. Smaller DER may require SCADA access depending on the interconnection voltage and interconnection study results. The Customer should be capable of communicating to support the information exchange requirements specified in IEEE Std 1547-2018 for all applicable functions that are supported in the DER. The Customer should contact The Company during the application process to obtain detailed information regarding SCADA communication and a “points list” that will identify the information to be exchanged. The Company should require remote trip, and/or permissive operation capability for all DER interconnections requiring SCADA access.

## **8. Power Quality**

- 8.1. When there is a concern that the DER will, or is causing power quality issues, the Company may require the installation of a power quality meter and monitoring system to permit ongoing assessment of compliance with the standards described above. DER with a capacity of less than 1000KW will generally not be required to install a power quality meter. If required, the Customer should consult the Company regarding the internal data logging settings. The Customer

should provide The Company reasonable access to the meter and associated stored data upon request.

**9. Metering Requirements**

- 9.1. Wholesale DER facilities must comply with the metering requirements of PJM and The Company.
- 9.2. State jurisdictional DER installations should be metered in accordance with the regulations of the State in which the interconnection occurs.

**10. Commissioning Tests and Verifications**

- 10.1. Commissioning and verification should be required to confirm that the system as designed, delivered, and installed meets the interconnection and interoperability requirements of this document and IEEE Std1547-2018.
- 10.2. When relay protection is utilized by the Customer, a written commissioning test plan and procedure should be provided for Company for review prior to commencement commissioning. The Customer should provide the Company a minimum of five business days advanced notice prior to the start of testing and should promptly inform the assigned Company representative regarding any schedule changes. The Customer should document the results of all testing in a report and submit it to the Company for review.
- 10.3. The Customer should perform verification testing of interface equipment (inverters, circuit breakers, control equipment, etc.) by a qualified technician during initial installation and commissioning in accordance with the manufacturer's documented procedures, the commissioning plan and IEEE Std 1547-2018. The Company reserves the right to witness verification testing and require written certification that the testing was successfully performed on all systems.
- 10.4. The Customer should be responsible for periodic testing and verification and should maintain records, test reports and logs of such activity in accordance with IEEE Std 1547-2018. The Customer should provide periodic testing records to the Company upon request.

## **Appendix A**

This informative section provides the Customer with insight regarding how the Company evaluates applications for interconnection, the successive review levels and the feasibility/impact study criteria used in determining if an application for interconnection is to be approved.

### **1. Estimated Limits for DER Installed on a Circuit**

In general, the Company distribution system is designed to serve an aggregation of retail load Customers and their associated on-site DER. There are practical limits to the amount of import (load) and/or export (generation or storage) that an individual Customer can have and be reasonably accommodated on the distribution system. While each application should be evaluated individually by taking into consideration customer net import/export and the detailed characteristics of the circuit, individual customer DER applications exceeding the values in the second column of Table A should not generally be interconnected to the distribution system.

The primary reason for this guideline is to maintain the operational flexibility of the distribution system. Large loads and large exports reduce the ability of distribution operations to reconfigure circuits during abnormal conditions, or maintenance scenarios. In addition, large loads and large exports from DER often require modifications to distribution system protection that may compromise system reliability.

The Company has estimated limits of the amount of DER (solar, wind, synchronous, induction or battery sourced) that may be connected to individual circuits in order to expedite the screening of interconnection applications and to facilitate the calculation of remaining available hosting capacity. These limits have been determined based on the voltage class of the circuit. The limits provide an estimate of the amount of aggregate decentralized DER<sup>1</sup> that may be connected to a circuit. The limits are shown in Table A - Decentralized DER Limits and apply to the aggregate nameplate DER capacity capable of operating in parallel with the distribution system. Large DER projects, large concentrations of DER, and DER at the far extents of distribution circuits will need to be investigated before these limits are reached.

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<sup>1</sup> Aggregate decentralized DER is the total nameplate capacity of all DER on a circuit that is spread out evenly across the physical footprint of the circuit and among the electrical phases of the circuit.

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Table A - Decentralized DER Limits			
Existing Circuit Voltage (kV Phase to Phase)	Maximum Total Rating (KVA) of Aggregate Decentralized DER Connected to a Circuit	Maximum Total Rating (KVA) of any Single or Group of DER in Close Proximity Receiving Expedited or Supplemental Review (Feasibility/Impact Study Required Above Rating Shown)	Maximum Reverse Power Flow at the Substation Power Transformer
2.4	600	300	Should Not Exceed the ONAN Nameplate Rating
4.34 4.16 4.8	1,000	500	
7.2 8.32	2,300	1,150	
11.5 12.0 12.47 13.2 13.8	4,000	2,000	
22.86 24.9	7,400	3,700	
34.5	11,000	5,500	

There may be cases where the aggregate distributed generation capacity exceeds the distribution circuit and/or substation power transformer’s native load, especially during times of minimum loading. This will be identified in the distribution system engineering studies and all protection requirements identified in the study need to be implemented.

**2. Technical Screening and Analysis of Interconnection Applications**

The customer should submit an application for interconnection in accordance with the specific State or PJM requirements for interconnection in which the interconnection is proposed. The state processes are defined on the generator interconnection web site for each State and FirstEnergy operating company. Follow the appropriate link on the FirstEnergy Generator Interconnection webpage at: <https://www.firstenergycorp.com/feconnect.html>

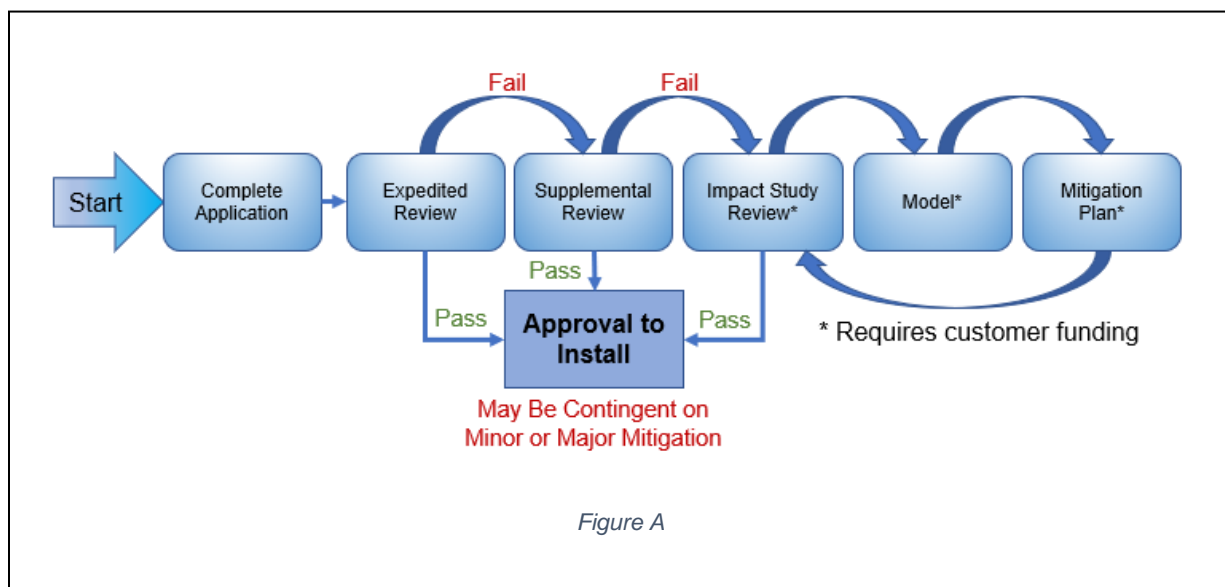


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If the Customer intends to participate in the wholesale market and is proposing to interconnect on a distribution facility, the Customer should follow the process identified by PJM on their website, <https://pjm.com/>.

The Company utilizes four levels of screening and analysis of interconnection applications; Completion Review, Expedited Review, Supplemental Review and Feasibility/Impact Study Review. As shown in **Error! Reference source not found., Error! Reference source not found.** once an application for interconnection is deemed complete, a project is subjected to a series of initial screens (a series of quick-check questions) and levels of review. If all screens are passed during a given level of review, Approval to Install may be granted immediately, or conditionally, provided the conditions of the approval are documented. However, if the application does not pass expedited review, regional engineering will apply supplemental review tests to determine the need for a detailed feasibility/impact study, which would involve circuit modeling and possible significant system mitigation recommendations. If any negative system impacts on voltage, power quality, or protection are identified during the expedited, or supplemental screening process, strategies for mitigating those impacts are identified and presented to the Customer without the need for detailed feasibility/impact study.



- a. Completion Review - The completion review process starts with a received application and attempts to answer the following questions:
  - Does the customer account number, name and address match company records?
  - Are the required forms completed with all the required information?

- Is the application signed by the Customer?
- Was the required single-line drawing, site plan and equipment specifications submitted?
- Were proper fees submitted, if required?

If the answer is “no”, to any of the questions listed in section a, the customer is sent a notice of deficiency and a request is made to resubmit or supplement the application.

b. Expedited Review – The expedited review process starts with a complete application and aims to answer the following questions:

- Is the application inverter based and UL1741SA certified?
- Is the applicant a secondary service customer?
- Is the aggregate DER rating less than 300 kW?
- Does the distribution circuit have enough remaining DER hosting capacity to accommodate the application?
- Is the annual production within the limits allowed by State regulation?
- Does the aggregate nameplate rating of the applicant’s system, plus any other existing systems owned by the applicant, or other customers, exceed the nameplate rating of the service transformer common to the applicant and other customers?

If the answer is “no”, to any of the questions listed in section b, the application is passed on for supplemental review, or the customer is sent a notice of deficiency and a request is made to resubmit or modify the application.

c. Supplemental Review – The supplemental review process starts with an application that has failed one, or more of the screening criteria in the expedited review process. The main question to be answered during supplemental review is, can the application be approved with only minimal, or no system mitigations required and without detailed circuit studies? The review is performed by regional engineering personnel that use their technical judgement, local knowledge and experience performing circuit analysis to decide if a Feasibility/Impact Study is needed to determine if the project can be interconnected to the distribution system safely, reliably, and without power quality issues. Some of the most important criteria to be considered are:

- How much DER hosting capacity remains on the subject circuit relative to the size of the DER proposed?
  - For an inverter-based certified DER application exceeding 300 kW, or for all non-certified DER, are the required utility grade relays shown on the single-line drawing and is the single-line drawing and site plan sealed by a professional engineer?
  - For an application exceeding 1000 kW, are the required utility grade relays and SCADA requirements shown on the single-line drawing and is the single-line drawing and site plan sealed by a professional engineer?
  - Is the applicant installing a system in an area further away from the substation on smaller wire, or is it closer to the substation where voltage rise, or voltage deviation is less likely to be an issue?
  - Is the minimum load on the proposed interconnection circuit higher than a typical circuit where voltage-rise, or voltage deviation is less likely to be an issue? Is it lower, where voltage-rise and deviation are more likely to be an issue?
  - Will the installation cause reverse power flow at locations where voltage regulation is installed?
  - Will the installation, combined with existing or approved DER on the circuit, cause reverse power flow through the substation and into the transmission system during minimum power flow conditions, or where distributed automation is planned or exists, minimum N-1 power flow conditions?
  - If an application consists of multiple single-phase customers (like an apartment complex, all solar housing community or condo community), will the DER contribute significantly to phase imbalance?
  - Is the application for rated DER capacity less than 50% of the value shown in the column titled, "Maximum Total Rating of Aggregate Decentralized DER Connected to a Circuit", in Table A?
- d. Feasibility/Impact Study Review – An impact study review is performed when simpler methods of screening applications, as described above and in state regulations, have not resulted in an approved application. An impact study review will be paid for by the Customer and will be performed by in-house Company staff, or at the discretion of the Company, by engineering consultants under contract with The Company to perform studies of this nature. The objectives of the impact study are to:

- Detail the impacts to the electric distribution system that would result if the DER was interconnected without modifications.
- Identify any modifications to the electric distribution system that would be necessary to accommodate the proposed interconnection.
- Identify any modifications to the applicant's interconnection design that would be necessary to accommodate the proposed interconnection
- Provide an estimate of the costs associated with performing the modifications identified above.

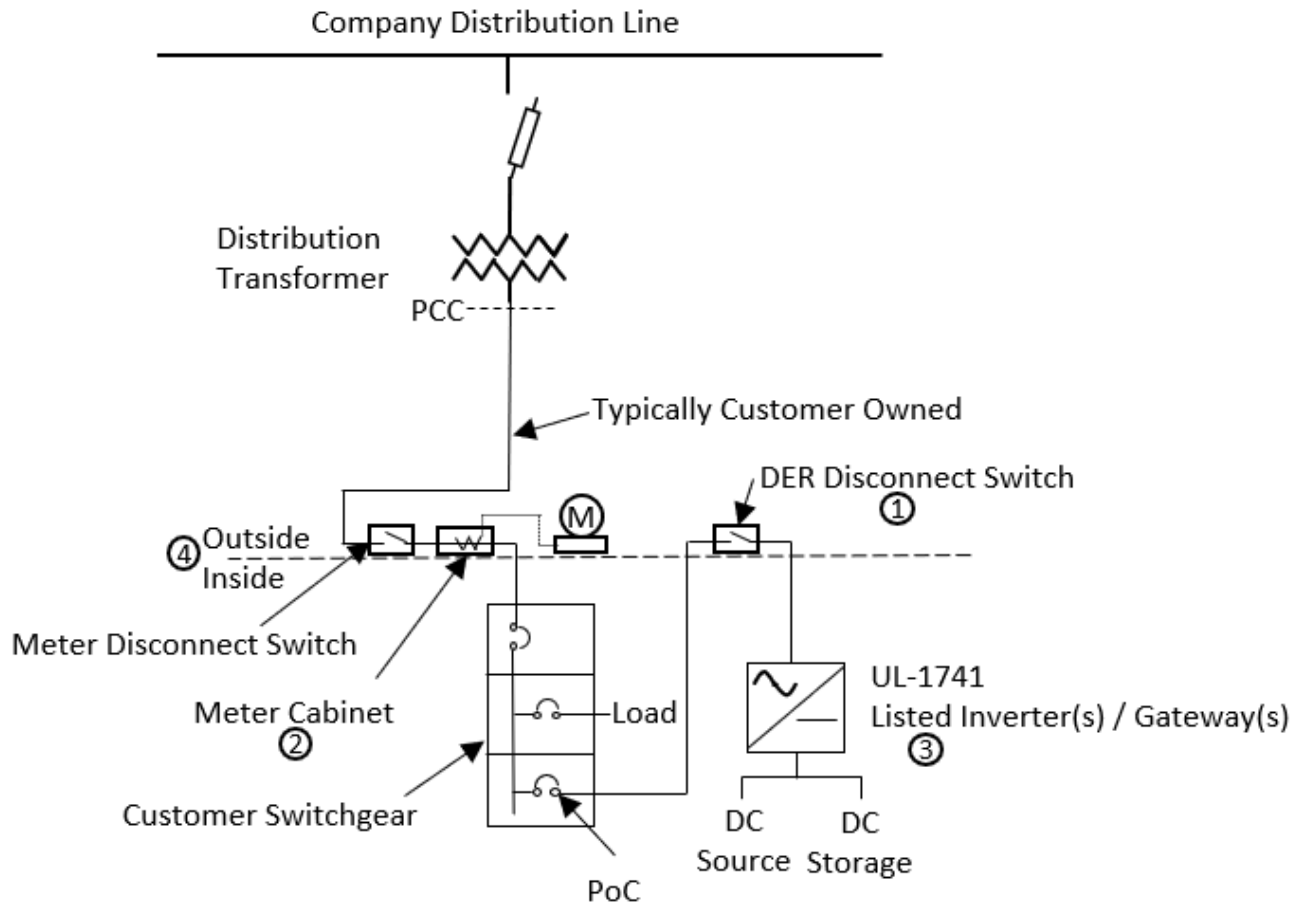
**3. Feasibility/Impact Study** Error! Reference source not found.

Table B provides the criteria and pass/fail thresholds to be used in determining if the proposed customer DER will have a negative impact on distribution circuit equipment, or if negative impacts to power quality and reliability are expected. Proposed customer DER failing any of the criteria outlined in **Table B – Technical Criteria and Thresholds**, should be provided with mitigation alternatives that are in compliance with The Company's distribution line and substation philosophies and design standards.

*Technical Interconnection Requirements and Study Criteria for Distributed Energy Resources Interconnected to Distribution Systems*

<b>Table B – Technical Criteria and Thresholds</b>		
Category	Criteria	Threshold
Voltage	Primary Over-voltage	Feeder voltage at any location not to exceed 1.05 pu (126V)
	Primary Voltage Deviation	Feeder voltage at any location to change less than 2% with taps & caps locked
	Regulation Device Voltage Deviation	Feeder voltage at any regulating device to change less than 1.25%
Load	Line and Device Thermal Rating	Power flow toward the feeder head not to exceed 100% of normal rating
	Sub Transformer Thermal Rating	Power flow toward the transmission system not to exceed 100% ONAN rating
	Regulator Thermal Rating	Power flow not to exceed 100% of summer rating, no load bonus
	Step Transformer Thermal Rating	Power flow toward the feeder head not to exceed 100% of nameplate rating
Protection	Breaker Relay Reduction of Reach	Breaker fault current not to decrease by more than 10% at any location
	Additional Element Fault Current	Feeder fault current not to increase by more than 10% at any location
Power Flow	Directional Real Power Flow To Transmission System	Reverse real power flow onto the transmission system is not permitted
	Directional Real Power Flow Regulators & Tap Changers	Reverse real power flow is not permitted at line voltage regulators, substation regulators, and tap-changers

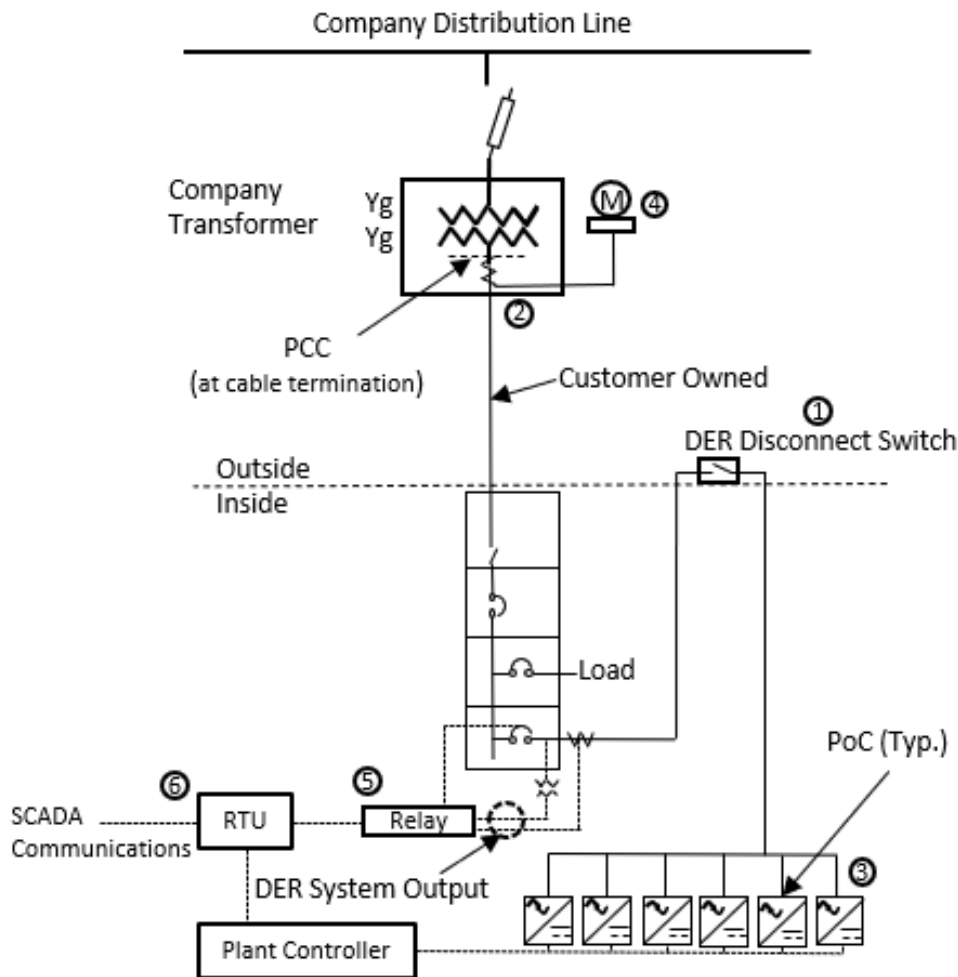
**Figure 1 – Typical Configuration – Certified DER Less than 300 KW**



**Notes:**

1. Lockable DER disconnect switch with a visible open is required to be installed outdoors. If outdoor installation is not practical, the Company may approve an alternate location.
2. No Customer connections are permitted in the Company meter cabinet
3. UL-1741 listed inverter meeting the requirements of IEEE-1547. Adjustable settings are to be as defined in Table 3, or as specified by the Company.
4. Outside / Inside is representative of the preferred configuration. Contact Company prior to application if metering equipment is not outside.

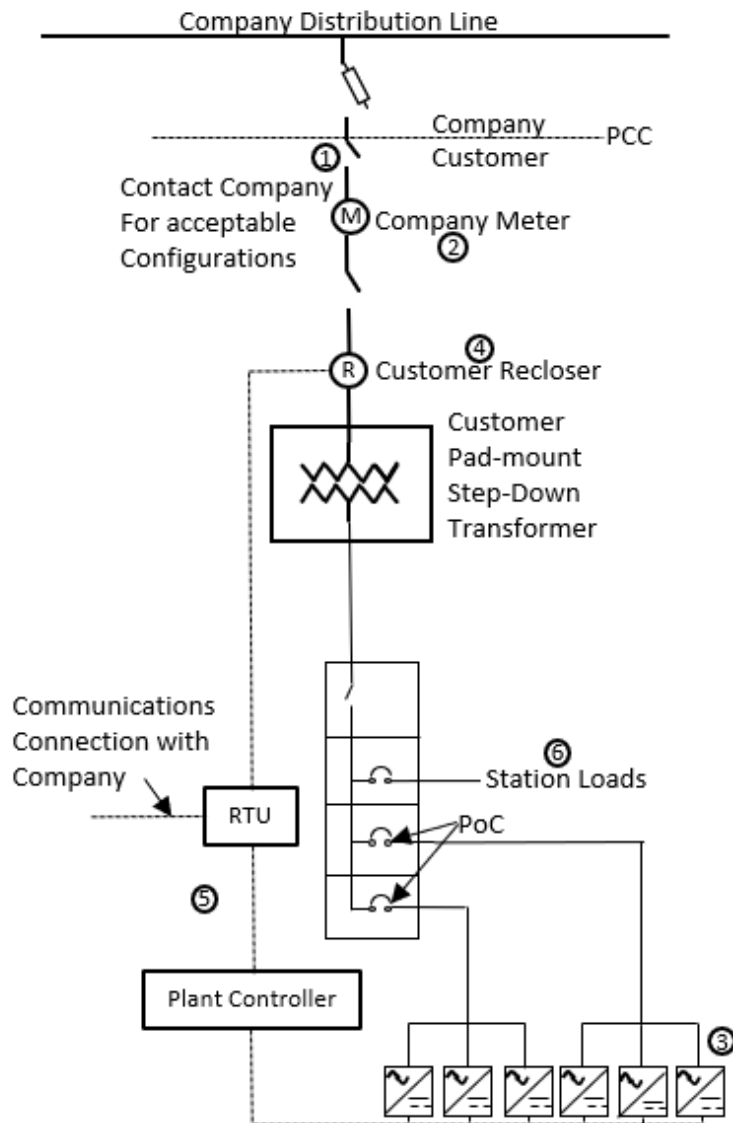
**Figure 2 – Typical Configuration – 3 Phase Certified DER – 300 KW or Greater**



**Notes:**

1. Lockable disconnect switch with a visible open is required to be installed outdoors near the Company meter, or electric service entry point. If outdoor installation is not practical, the Company may approve an alternate location.
2. No Customer connections are permitted in the Company transformer cabinet other than service cables to be terminated by the Company
3. UL-1741 listed inverters meeting the requirements of IEEE-1547. Adjustable settings are to be as defined in Table 6 & 7, or as specified by the Company
4. Company meter equipment located inside padmount transformer only with specific approval. See Company Guide for Electric Service.
5. SEL 751 or equivalent relay required if inverter aggregate rating is 300 kW, or larger. Multiple relays may be used as required.
6. RTU and optional plant controller required for SCADA, 1000 kW, or larger

Figure 3 – Typical Configuration – Grid Connected Certified DER

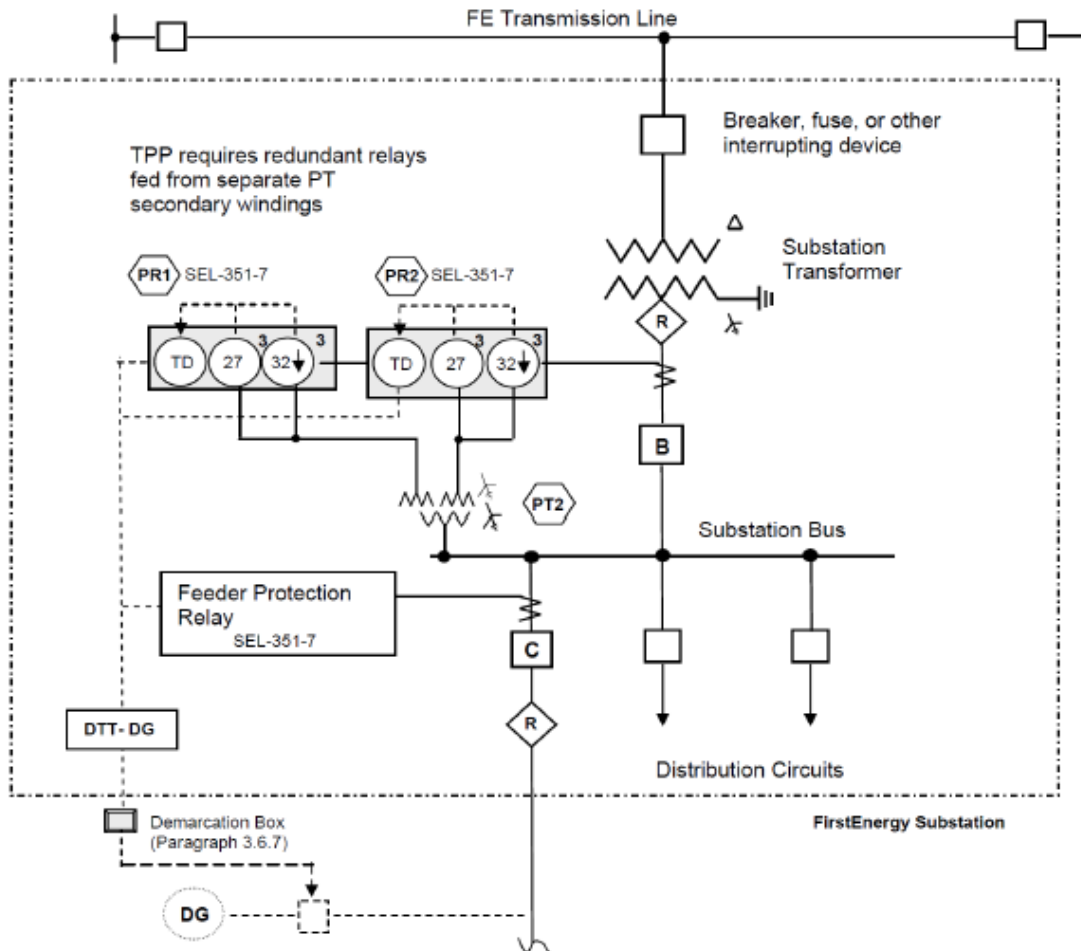


**Notes:**

1. Lockable disconnect switch with a visible open is required to be installed outdoors near the Company meter, or electric service point.
2. No Customer connections are permitted in the Company meter equipment area
3. UL-1741 listed inverters meeting the requirements of IEEE-1547. Adjustable settings are to be as defined in Table 2, or as specified by the Company
4. Recloser with integral , or external multi-function relay required if inverter rating 300 kW, or larger
5. RTU and optional plant controller required for SCADA, 1000 kW, or larger
6. Contact Company for metering and service requirements



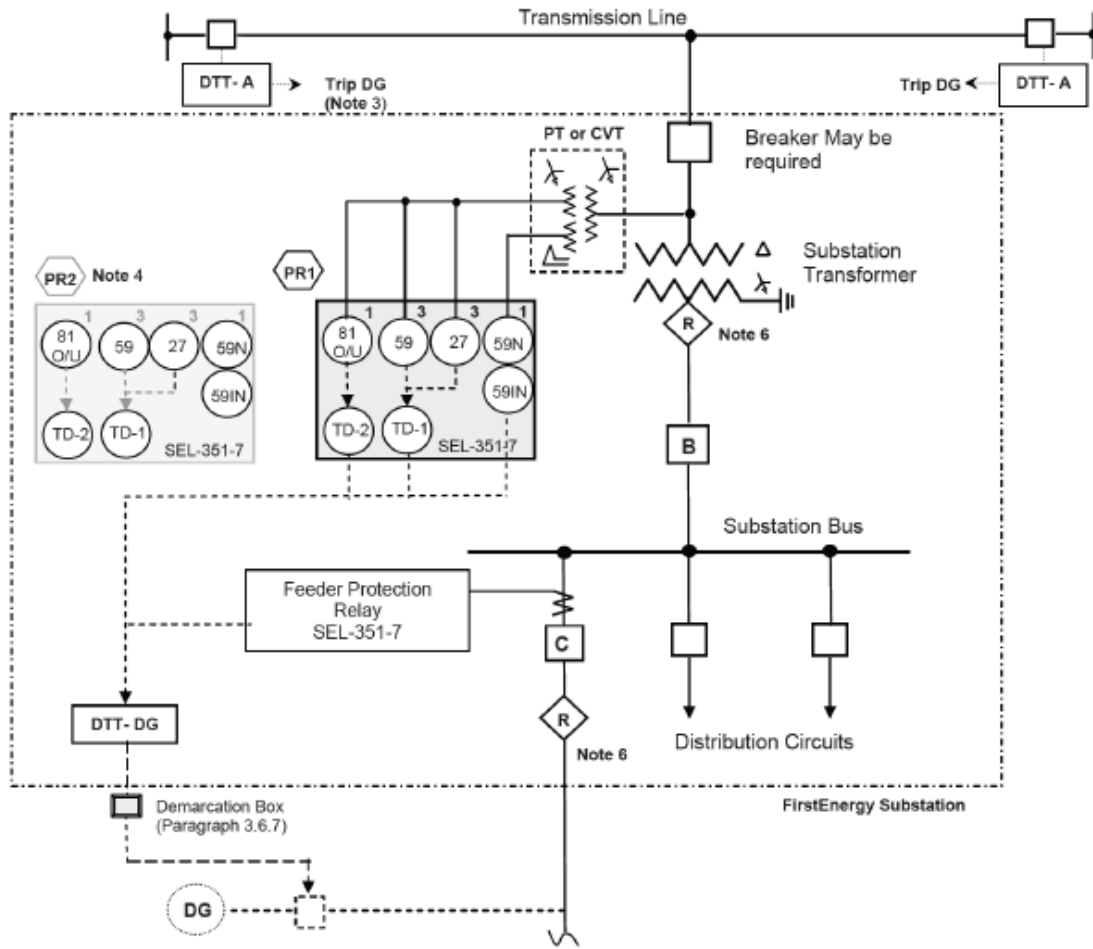
Figure 4 – Typical Substation Configuration – DTT Required



**Notes:**

1. This protection scheme functions to detect transformer high-side faults and applies when the DG is potentially capable of sustaining the substation transformer load upon loss of transmission source.
2. The DG will not be able to back feed power to transmission system with this protection scheme. This scheme offers a lower-cost protection solution to DG owner as compared to the design shown in Figure 6.
3. The DG will trip via DTT if transformer's power flow in the forward direction is lost or reverses; it will also trip for Undervoltage condition from 27 relay. 27 Time delay allows for transient under-voltages.
4. This protection scheme prevents the DG from permanently supplying a fault on the high voltage side of the transformer, but relies on high side relaying to detect and clear fault.

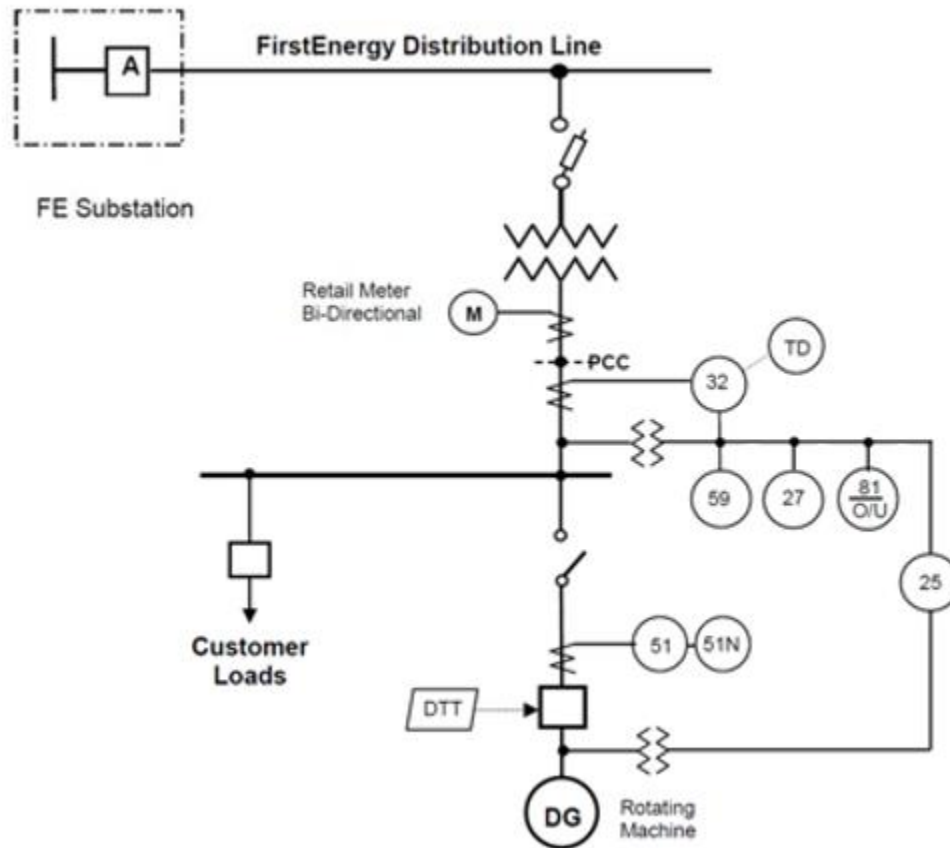
Figure 5 – Typical Substation Configuration – Substation Back-feed & DTT



**Notes:**

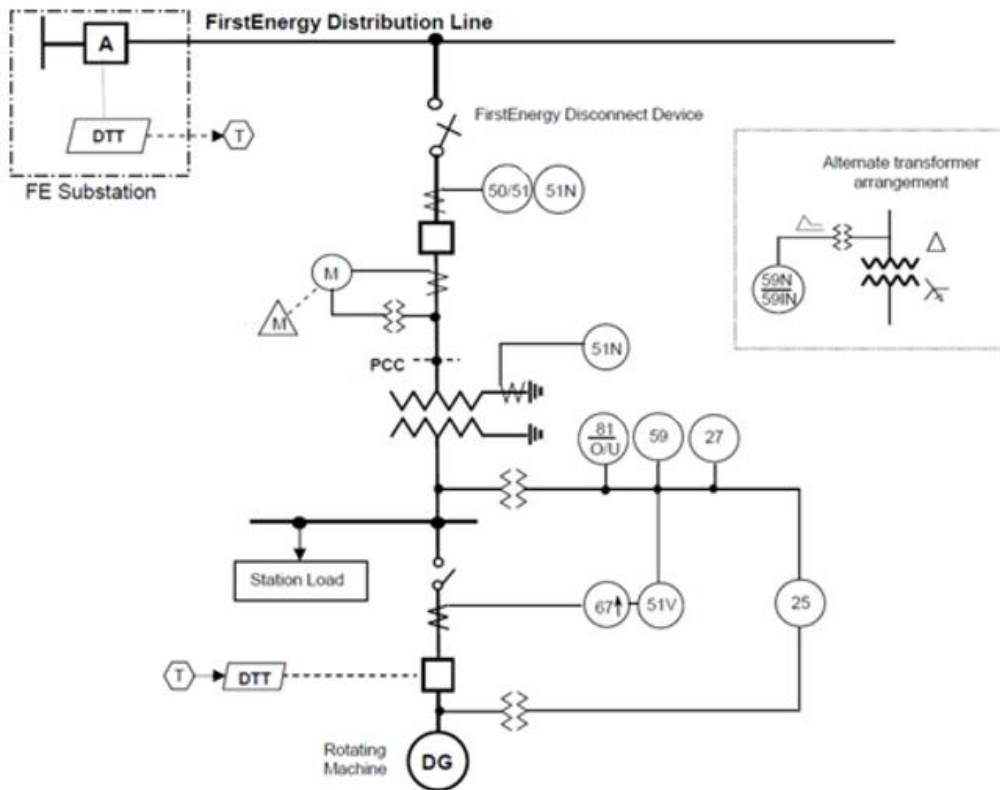
1. This protection scheme functions to detect transformer high-side faults and applies when the DG is capable of sustaining the substation transformer load upon loss of transmission source.
2. Use when DG will be permitted to back feed transmission.
3. DTT-A scheme requirement will be determined on case-by-case basis by TPP. This determination is a function of DG capacity relative to potentially islanded load if transmission source is lost. (2:1 load/gen. ratio is typically used by ED TPP)
4. If DTT-A scheme is not used, redundant PR1 and PR2 relays are required.
5. 59N/59IN required to detect ground faults on transmission side.
6. Tap Changer Controls may need to be replaced to allow for reversed power flow.

Figure 6 – Typical Configuration – Secondary Connected Rotating Generator



Relay	Function	When Required
27	Undervoltage Detection	All Installations
59	Oversvoltage Detection	All Installations
81O/ 81U	Over / Under Frequency	All Installations
25	Synchronizing	For Synchronous machines
51G	Detect system ground faults	When DG will supply ground fault current
59G	Detect system ground faults	When interconnection transformer HS winding is ungrounded
32	Reverse Power Relaying	Islanding protection for non-export customer see Section 3.5
51/51N	Phase/Neutral Overcurrent	All Installations
DTT	Direct Transfer Trip	Protection study required - See Section 3.6 for requirements

Figure 7 – Typical Configuration – Primary Connected Rotating Generator



Relay	Function	When Required
27	Undervoltage Detection	All Installations
59	Overvoltage Detection	All Installations
81O/ 81U	Over / Under Frequency	All Installations
25	Synchronizing	For Synchronous machines
59N / 59IN	Ground Fault detection –Time / Inst	When interconnection transformer HS winding is not effectively grounded
67	Detect system phase faults	Generally required for all synchronous machines - Protection study required
51V	Detect system phase faults	May be needed when 67 not able to detect remote faults
51/51N	Detect system phase and ground faults	All Installations
DTT	Transfer Trip Receiver	May be required when 81O/U or 27/59 relays may not adequately detect an islanding condition.