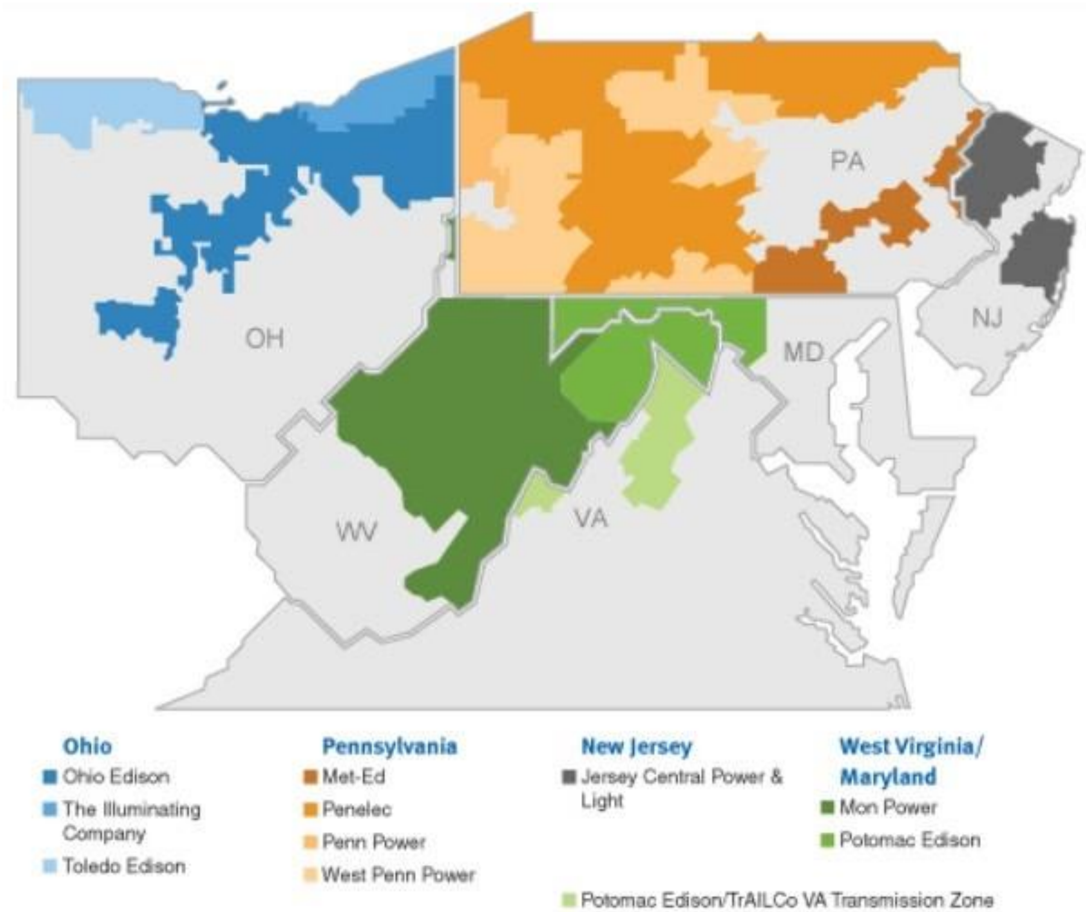

Customer Guide for Retail Interconnection of Electric Power Producing and Storage Facilities Commercial/Industrial – Three Phase Inverter Based

January 2024

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1.0 Introduction

This guide is published to provide pertinent information that will assist customers and their engineers, builders, and contractors in planning for and obtaining a safe and prompt interconnection of Customer owned electric power-producing and storage facilities that run in parallel with the FirstEnergy Operating Company (Company) distribution system. These facilities shall be referred to in this document as Distributed Energy Resources (DER).

The guide conveys general knowledge and does not provide every detail or every requirement. Furthermore, the information is supplementary to, and does not intentionally conflict with the National Electrical Code (NEC), the National Electrical Safety Code (NESC), the Company’s current applicable Tariffs, or such state and municipal laws and ordinances as may be in force and applicable within the cities, towns, or communities in which the Company furnishes electric service. It is always necessary for customers and contractors to comply with state statutes, local ordinances, and the Company's Tariffs on file with the State in which they reside. To the extent that any information included in this Guide contradicts any terms in the Company’s current applicable Tariff, the Tariff provisions shall govern.

Mandatory rules of this document are those that identify actions that are specifically required or prohibited and are characterized by the terms **shall** or **shall not**. This Guide is subject to amendment from time to time and will be re-issued on an as needed basis. It is the responsibility of the user to obtain the current version.

The current edition of this Guide supersedes all previous editions or versions. The current edition of this Guide is available at
https://www.firstenergycorp.com/feconnect.html

2.0 Definitions

area electric power system (Area EPS): An EPS that serves Local EPSs. An area EPS is usually owned and operated by the power distribution Company

authority having jurisdiction: Authority having the rights to inspection and approval of the design and construction of Local EPS premise electrical systems

clearing time: The time between the start of an abnormal condition and the DER ceasing to energize the *Area EPS*. It is the sum of the detection time, any adjustable time delay, the operating time plus arcing time for any interposing devices (if used), and the operating time plus arcing time for the interrupting device (used to interconnect the DER with the *Area EPS*).

distributed energy resource (DER): A source of electric power that is not directly connected to a bulk power system. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with IEEE-1547 is part of a DER. Controllable loads used for demand response are not included in the definition of DER

electric power system (EPS): Facilities that deliver electric power to a load. Includes the area EPS and the local EPS

energy Storage device: A piece of equipment that captures energy produced at one time, stores that energy for a period of time, and delivers that energy as electricity at a future time.

flicker: The subjective impression of fluctuating luminance caused by voltage fluctuations. NOTE—Above a certain threshold, flicker becomes annoying. The annoyance grows very rapidly with the amplitude of the fluctuation. At certain repetition rates even very small amplitudes can be annoying (IEEE Std 1453).

inadvertent export: The unscheduled export of power from a DER, beyond a specified magnitude and for a limited duration, generally due to fluctuations in load-following behavior.

interconnection: The result of the process of adding DER to an Area EPS, whether directly or via intermediate Local EPS facilities.

interconnection equipment: Individual or multiple devices used in an interconnection system.

interconnection system: The collection of all interconnection and interoperability equipment and functions, taken as a group, used to interconnect a DER to an Area EPS.

island: A condition in which a portion of an Area EPS is energized solely by one or more Local EPSs through the associated PCCs while that portion of the Area EPS is electrically separated from the rest of the Area EPS on all phases to which the DER is connected. When an island exists, the DER energizing the island may be said to be "islanding".

local electric power system (Local EPS): An EPS contained entirely within a single premises or group of premises. The local EPS is usually owned and operated by the Customer

nameplate ratings: Nominal voltage (V), current (A), maximum active power (kW), apparent power (kVA), and reactive power (kvar) at which a DER is capable of sustained operation.

parallel operation: The sustained state of operation over 100 milliseconds which occurs when a DER is connected electrically to the electric distribution system, and thus has the ability for electricity to flow from the small generator facility to the electric distribution system.

point of common coupling (PCC): The point of connection between the Area EPS and the Local EPS. Equivalent, in most cases, to “service point” as specified in the National Electrical Code® (NEC®) and the National Electrical Safety Code® (NESC®)

point of distributed energy resources connection (point of DER connection–PoC): The point where a DER unit is electrically connected in a Local EPS and meets the requirements of this standard exclusive of any load present in the respective part of the Local EPS

supplemental DER device: Any equipment that is used to obtain compliance with some, or all the interconnection requirements of IEEE-1547

3.0 State Interconnection Rules and Regulations

Retail interconnections, which primarily include net energy metered customers, are subject to State interconnection rules and regulations. State rules define the interconnection review procedure and provide details such as allowable fees and assignment of construction costs. They also impose processing deadlines and reporting requirements for utilities. The state-specific interconnection rules and standards are shown in Table 1 below. These standards may be revised from time-to-time. These documents are available via the State Commission’s website

Table 1 – Rules & Regulations for Retail Interconnections

Maryland	Code of Maryland Regulations (COMAR), Title 20 PSC, Subtitle 50, Chapter 9 Small Generator Interconnection Standards, Chapter 10 Net Metering
Ohio	Ohio Administrative Code, Chapter 4901:1-22, Interconnection Services, Chapter 4901:1-10-28
Pennsylvania	Pennsylvania 52 PA Code Chapter 75, Subchapter C Interconnection Standards , Subchapter B Net Metering
New Jersey	New Jersey Administrative Code, N.J.A.C. 14:8-4, Net Metering for Class 1 Renewable Energy Systems, N.J.A.C. 14:8-5, Intetrconnection of Class 1 Renewable Energy Systems
West Verginia	West Virginia PSC, Title 150, Series 33, Rules Governing Electric Utility Net Metering Arrangements and Interconnections

4.0 Applicability

The interconnection requirements set forth in this document describe the minimum operating characteristics, equipment, and protective devices the Company requires for operation of its electric distribution system in parallel with DER owned by a Customer. This guide was developed for those Customers with three-phase electric service at either primary or secondary voltages and interconnecting inverter based DER under the jurisdiction of individual state regulations. (Company retail tariff-based interconnection) These interconnection requirements are also applicable to developers of DER facilities intending to participate in retail community solar, or other retail aggregation programs allowable under individual state regulations.

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 shall 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 shall be obtained for electrical system modifications related to back-up power systems as described and defined in the NEC.

5.0 Application Procedure

The Customer shall submit an application prior to installing, operating, or making significant changes to a DER utilizing application forms and instructions available at https://www.firstenergycorp.com/feconnect.html A capacity increase, or decrease, exceeding 5% is a significant change requiring a modified application. In the case of multiple Customer accounts being impacted by a single project, the Customer shall submit a specific application for each account. However, the Customer is permitted to utilize a common site plan and single-line drawing. The Customer will need to click on the link for the appropriate FirstEnergy Operating Company and follow the instructions specific to each State jurisdiction. If assistance is required during the application process, local Company contact information is provided at the web address listed above.

It is recommended that Customers intending to make application for DER greater than 500 kW contact the Company prior to making application. The Company will assign an engineer to review conceptual plans and have informal discussions with the Customer's engineer regarding the project design requirements.

6.0 Design Requirements

6.1 For applications having a rated inverter capacity greater than 500 kW the Company shall require design drawings and relay settings to be signed and sealed by a Professional Engineer. At the discretion of the Company, design drawings for smaller sized systems may need to be prepared by a Professional Engineer.

6.2 The Customer's design, installation and operation shall meet the requirements of IEEE 1547-2018, except as noted in paragraph 6.3.

6.3 The Customer DER shall 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.

Table 2

Function (1547-2018 term**)	UL 1741 SA Term and section	SA Testing Required*	Function Enabled?
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

**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.*

***Not all IEEE 1547-2018 functions are included in this table*

Note 1: Power Factor shall be set = 1.0

Note 2: The Company intends to change the requirements of paragraph 6.3 when equipment type-tested and certified to the latest version of IEEE 1547.1 become available. (Estimated timeframe – June,2022)

6.4 An equipment package shall 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.

6.3 The DER shall 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) shall be either inverters, certified as described in 6.3, or circuit breakers (including reclosers) with protective relays approved by the Company. (See 6.10) Unless specifically required by and approved by the Company in writing, the settings for automatic operation shall conform to the following Table 3. (See 6.10 for relays performing a back-up function) No setting shall be changed by the Customer after initial commissioning unless specifically authorized by the Company in writing.

Table 3 Company Voltage and Frequency Settings Requirements for Inverters

Voltage Range (% of base)	Maximum Total Clearing Time (S)	Frequency (Hz)	Maximum Total Clearing Time (S)
V<45	0.16	<57	0.16
45≤V<60	1	<59.5	2
60≤V<88	2	>60.5	2
110<V<120	1	>62	0.16
V≥120	0.16		

6.5 Following a disconnect of the DER due to voltage or frequency excursion, the DER facility shall 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.

In the case of a Customer owned relay trip, a qualified person shall 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 6.9)

Customers who are connected via SCADA with the Company Distribution Control Center (DCC), shall 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)

6.6 All DER connecting behind a 3 phase PCC, shall 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 shall be installed outdoors in the immediate vicinity of the electric meter, or service entrance to facilitate access by Company personnel. The switch shall be clearly marked, "Generator Disconnect Switch," with permanent 3/8 inch or larger letters.

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 shall 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 shall 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.

6.7 If the Customer has a previously approved indoor meter location, a consultation with the Company regional engineering department is required prior to submitting plans. Depending on the details of the situation, unique requirements may be needed. These requirements may include relocation of the meter, relocation of instrument transformers, and/or special signage requirements.

6.8 No attachments by the customer or the customer’s agent are permitted to Company-owned meters, meter circuits, or ancillary meter devices. The following are considered un-authorized connections when not made, installed, or performed by a Company employee or an authorized representative of the Company:

- Any adapter placed between the revenue meter and meter socket.
- Attachments or connections to the potential or current circuits of transformer rated revenue meters.
- Any connection inside the meter socket.

- Any connection made inside a cubical, or meter cabinet dedicated to Company metering use

6.9 The use of an energy storage device, like batteries, or other non-renewable resources, connected in tandem with renewable energy generation sources, such as inverter based solar PV systems, is permitted under the Company Tariff for Electric Service. Charge and discharge of a storage device, or operation of nonrenewable generation is permitted while operating in parallel with the area EPS, but only when power is not being exported as measured at the PCC. The storage device, or non-renewable generation, shall be located on the Customer side of the DER automatic protective device. (See section 6.1) The Customer shall provide the Company with control system specifications, acceptable to the Company, that indicate the mode of operation will not permit export while operating in parallel with the area EPS. Inadvertent export due to delay in control system response is permitted when explicitly approved by the Company. The Customer shall define the amount of inadvertent export power, total energy, and duration as part of the application submittal.

6.10 Customer DER interconnections rated above 500kW (aggregate inverter nameplate rating), shall 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 shall 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.(See Figure 2) Relays, circuit breakers, and reclosers shall 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

The Customer shall 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 4 are to be considered by the Customer when designing their protection settings. For relay device functions listed as “back-up” in Table 4, 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 3. The Customer shall 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.

The Customer shall provide an Uninterruptable Power Supply (UPS) to power the protective device and relay should the normal power source fail. The UPS shall be capable of supplying back-up power for a minimum of 1 hour.

Table 4

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 Open Phase Detection	No

6.11 The Customer shall 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 shall 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.

7.0 Communications and Control

7.1 In general, Customer DER interconnections rated 1000 KW (total inverter nameplate rating), or larger, shall 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 shall be capable of communicating to support the information exchange requirements specified in IEEE-1547-2018 for all applicable functions that are supported in the DER. The Customer shall 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 shall require remote trip, and/or permissive operation capability for all DER interconnections requiring SCADA access.

7.2 In some cases, (generally rated capacity > 1000 KW) the Company may require the Customer to install direct transfer trip (DTT) between Company owned protective devices and Customer owned protective devices. The requirements for DTT, if needed, will be based on the results of the interconnection study performed by the Company.

8.0 <u>Power Quality</u>

The requirements for acceptable flicker levels shall be in accordance with the latest version of IEEE Std 1453, Recommended Practice for the Analysis of Fluctuating Installations on Power Systems. Short and long-term perception of flicker shall be within the planning and compatibility levels identified in this standard. Mitigation measures necessary to comply with these requirements shall be at the Customer’s expense. The DER shall not be a source of excessive harmonic voltage or current distortion and/or voltage flicker. Limits for harmonic distortion are as published in the latest issue of IEEE 519, "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems."

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 shall consult the Company regarding the internal data logging settings. The Customer shall provide the Company reasonable access to the meter and associated stored data upon request.

9.0 <u>Commissioning Tests and Verifications</u>

Commissioning and verification shall be required to confirm that the system as designed, delivered, and installed meets the interconnection and interoperability requirements of this document and IEEE-1547.

9.1 The Customer shall perform verification testing of interface equipment (inverters, circuit breakers, control equipment, etc.) by a qualified technician during initial installation in accordance with the manufacturer’s documented procedures and IEEE-1547. The Company reserves the right to witness verification testing or require written certification that the testing was successfully performed on all systems, regardless of rated size.

9.2 When relay protection is utilized by the Customer, a written commissioning test procedure shall be provided for Company approval prior to commencement of such testing. The Customer shall provide the Company five business days advanced notice prior to the start of testing and shall promptly inform the assigned Company representative regarding any schedule changes. The Customer shall document the results of all testing in a report and submit it to the Company for review.

9. 3 Functional islanding testing is to be performed with a minimum of 30% of rated output capacity under normal Customer and circuit loading conditions. The Customer shall coordinate with the Company to determine whether proper functional testing conditions exist.

9.4 The Customer shall be responsible for periodic testing and verification and shall maintain records, test reports and logs of such activity in accordance with IEEE 1547. The Customer shall provide periodic testing records to the Company upon request.

10.0 Company Preliminary Approval Process

The Company will perform a review of the application documents submitted and evaluate the need for any upgrades to Company facilities due to the DER installation. If the application does not meet approval requirements, or upgrades to Company facilities will be required, the Customer will be notified. For larger applications, or for smaller applications on distribution circuits with high penetration, a detailed interconnection study may be required. If the application meets the approval requirements, an “Approval to Install” notification shall be issued. This notice serves as:

- Notification that the Company has received the Customer’s application
- Notification that the Company has not found any deficiencies with the application
- Notification that the application has been preliminarily approved for interconnection

The Approval to Install is a preliminary approval and is for operational purposes only. It is the Customer’s responsibility to ensure compliance with any requirements documented in the Approval to Install, all local, state, and federal ordinances, statutes, regulations, or other legal requirements.

11.0 Upgrades to Company Facilities

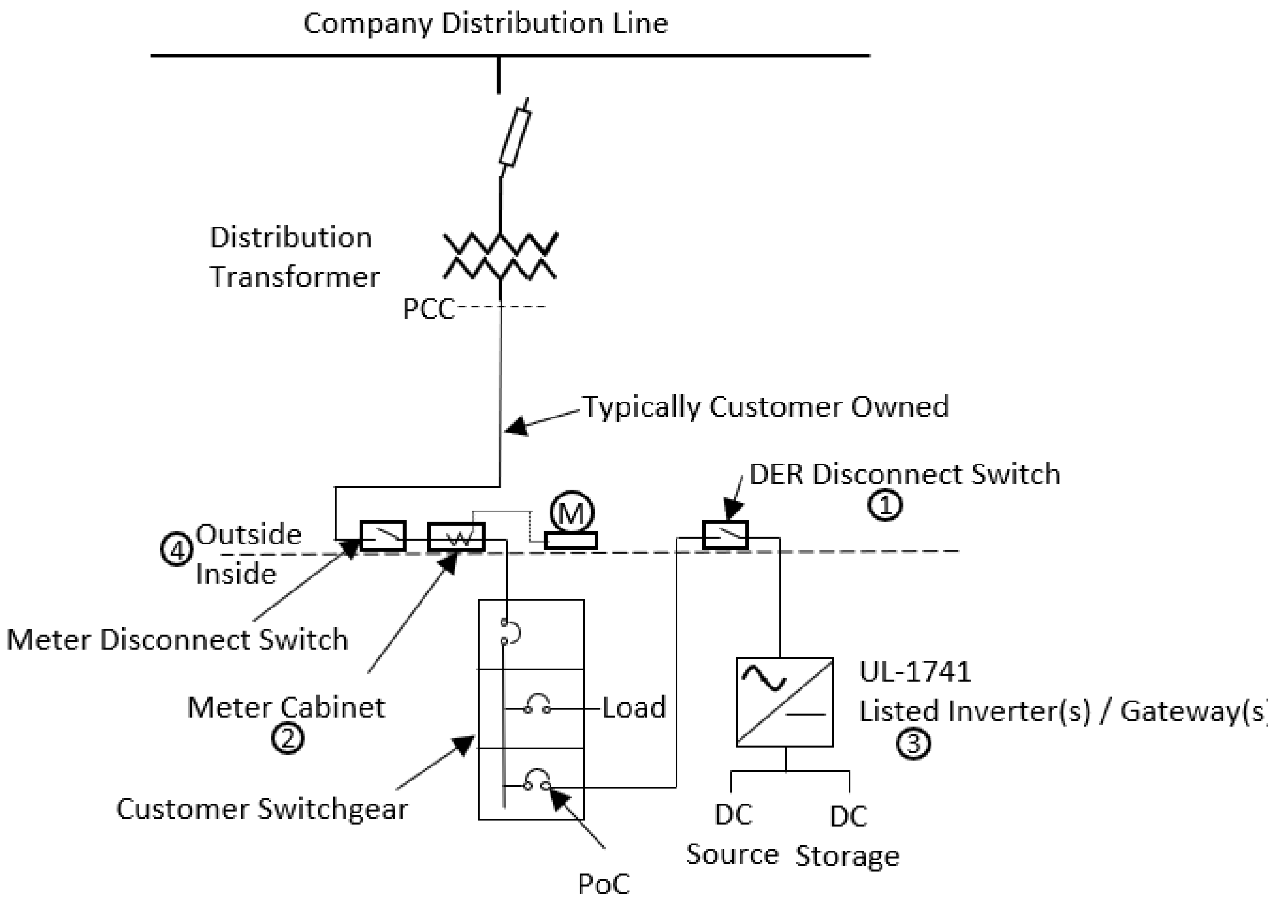
Depending on the rated capacity and location of a proposed DER, the Company may determine that an upgrade is required to its facilities to safely and reliably interconnect with the Company area EPS. In such cases, the Customer will be informed of the estimated cost of the upgrades to Company facilities needed to accommodate the DER. All costs associated with DER related facility upgrades will be the responsibility of the Customer. If the Customer desires to proceed with upgrades, the Customer will be given instructions on how to open a work request with the Company. The work request process will result in a Fixed Cost Billing Agreement being generated by the Company. Execution of the Billing Agreement, payment and completion of the work request is required prior to the Company issuing an Approval to Operate (See section11.0).

12.0 Company Final Approval Process

After the Customer has received an Approval to Install from the Company, completed the installation, obtained all required approvals from State and local authorities having jurisdiction, and paid the Company for any required facility upgrades, the Customer shall submit the Part 2 (final application) documents. These documents can be obtained at https://www.firstenergycorp.com/feconnect.html and are unique to each Company location / State. The Customer shall note any as-built changes to the original application documents and submit documentation/proof of proper commissioning tests in accordance with IEEE 1547 and any other Company requirements. The Company shall perform a review of the application documents, assess if the Company has completed any required facility upgrades, and determine if final approval is warranted. The Company may require a witness test as part of its final review. If final approval is granted, an Approval to Operate notice will be issued by the Company. This notice shall serve as the Company's final communication regarding the DER application process.

It is often necessary for the Company to change the type of meter installed at the Customer location to properly bill net-meter accounts. If required, meter change-out orders are automatically issued by the Company at the same time an Approval to Operate notice is issued.

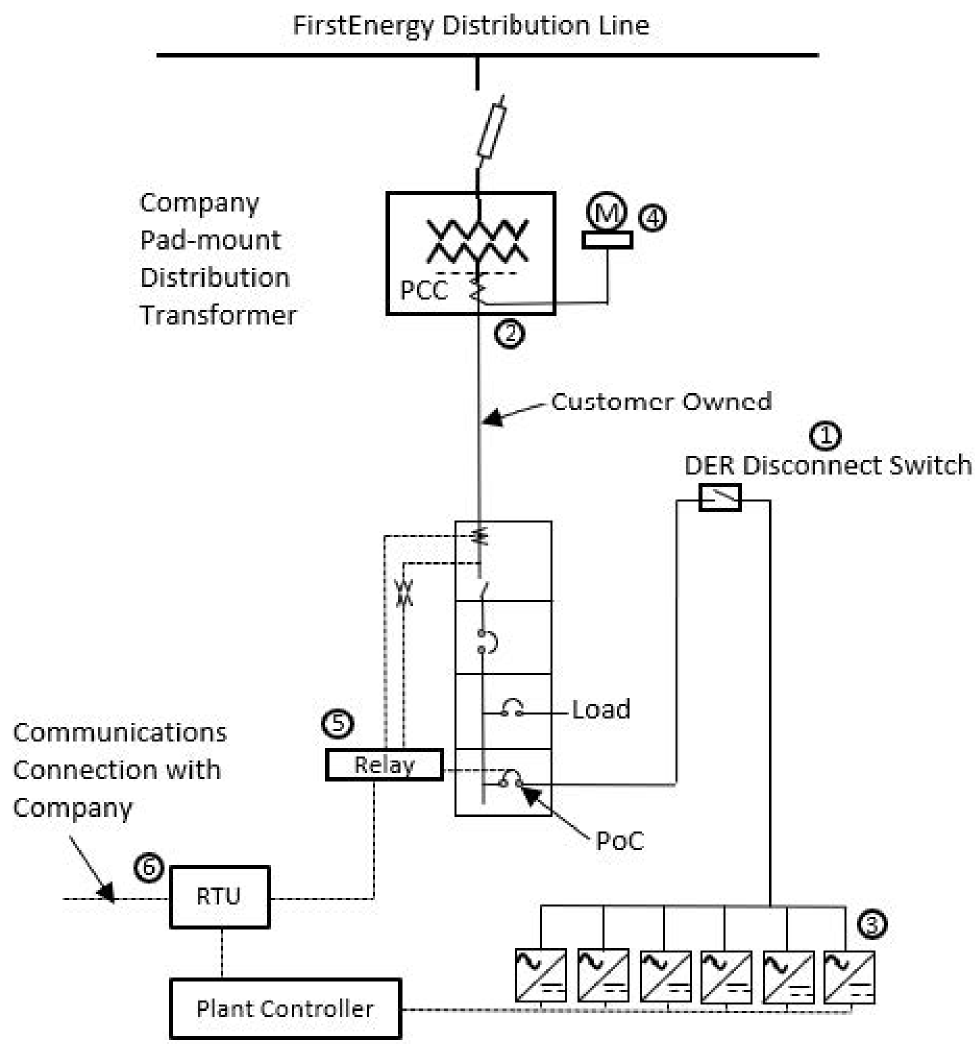
Figure 1 – Typical Configuration – 3 Phase – Less than or equal to 500 kW



Notes:

1. Lockable DER disconnect switch with a visible open is required to be installed <u>outdoors</u>. 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.

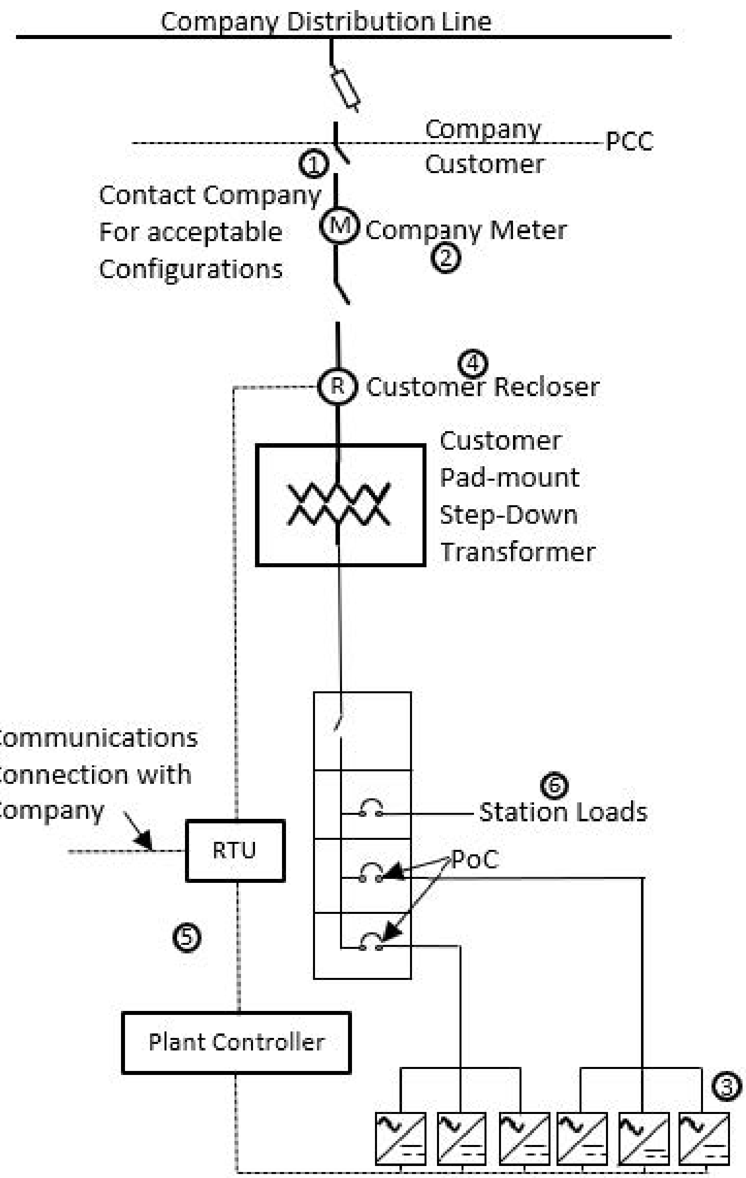
Figure 2 – Typical Configuration – 3 Phase – Greater than 500kW



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 meter cubical 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 2, 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 rating above 500 kW.
6. RTU and optional plant controller required for SCADA, 1000 kW, or larger

Figure 3 – Typical Configuration – 3 Phase, Grid Connected 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 greater than 500 kW.
5. RTU and optional plant controller required for SCADA, 1000 kW, or larger
6. Contact Company for metering and service requirements