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AN EXELON COMPANY

PHI DER Technical Interconnection Requirements

Updated 11/25

Choose an item.

1. Table of Contents

1. Introduction

1.1. Scope

This Technical Interconnection Requirements (TIR) document provides guidance for grid interconnection and parallel operation with the distribution grid in the PHI service territories. It provides criteria for PHI engineers, as well as customers and developers planning to interconnect distributed energy resources (DERs) with the Utility distribution system. DERs can be gas or diesel generators, inverter-connected PV, energy storage, fuel cells, microturbines and other configurations. Both medium voltage and low voltage connections are covered. The requirements apply to all aspects of DER connection and operation with the Utility grid.

The document addresses responsibilities of the Interconnecting Customer (IC) related to the grid integration, point of connection, and general system performance when interconnecting to the PHI distribution grid. It includes operational performance, power quality, protection, monitoring, control, and telemetry requirements. Interoperability with other grid equipment as well as metering, commissioning test and verification requirements are addressed. This document also covers specific operating requirements and any special protection that may be required for connections on radial or network locations in the distribution grid.

1.2. Precautions and Limitations

All revisions to this TIR document are subject to PHI general counsel review for compliance with the applicable state laws, rules and regulations, including but not limited to those specified in Section 3.2. In addition to the three-year cycle review, the TIR shall be reviewed by PHI general counsel during and/or following any proceedings which intend to modify the applicable state laws, rules or regulations to maintain alignment.

This TIR document is applicable to interconnections on the distribution grid, as classified by each PHI service territory. Requirements for interconnection to the transmission system are subjected to the Technical Considerations Covering Parallel Operation of Customer Owned Generation and Exelon Utilities Transmission Facility Interconnection Requirements

1.3. Responsibilities

1.3.1. Customer-Owned Generating Equipment

The IC is responsible for designing, installing, operating, and maintaining its' own equipment in accordance with interconnection agreements and applicable standards — for example, IEEE Standard 1547, the National Electrical Code, other Safety Codes, North America Electric Reliability Council rules (applicable for independent system operators), and all applicable laws, statutes, guidelines, and regulations. The IC's responsibilities includes installing, setting, and maintaining all protective devices necessary for safe grid integration and to protect the IC's and utility's facilities.

1.3.2. PHI Managed and Operated Distribution System

Requirements specified in these DER requirements are also intended to complement PHI efforts and responsibility to maintain distribution grid safety, power quality and reliability. Continuity and quality of service to all customers is a key responsibility of the Utility.

1.3.3. Requirements Related to Ongoing Utility Upgrades

The Utility system is constantly changing due to shifts in loading and the addition or removal of generation. The possibility exists that a change in the Utility system may cause a change in the protection or other requirements at the generation interconnection. If such a system change occurs, it is then the responsibility of the generator owner to make the necessary changes to meet these changing grid requirements.

2. Definitions and Acronyms

2.1. Definitions

Terminology used in this document is intended to follow definitions and usage in IEEE Standard 1547™-2018, other related IEEE, IEC, and ANSI standards. In some cases, terms related to the FERC-SGIP and NFPA related codes such as the US National Electric Code, NFPA-70 are used.

A few definitions are provided here for convenience or if unique to this document.

2.1.1. ***Account*** *– An account is one metered or un-metered rate or service classification which normally has one electric delivery point of service. Each account shall have only one electric service supplier providing full electric supply requirements for that account. A premise may have more than one account.*

2.1.2. ***Company*** *– PHI doing business as Atlantic City Electric (ACE), Delmarva Power & Light (DPL) and Potomac Electric Power Company (Pepco).*

2.1.3. ***Buffer zones*** *– Are limits, defined and used to protect the grid by providing a safety margin added to DER integration limits, for example, limits to prevent reverse power on a substation power transformer.*

2.1.4. ***Bulk power system (BPS)*** *– Any electric generation resources, transmission lines, interconnections with neighboring systems, and associated equipment.*

2.1.5. ***Customer*** *– Any adult person, partnership, association, corporation, or other entity: (i) in whose name a service account is listed, (ii) who occupies or is the ratepayer for a premise, building, structure, etc., and (iii) who is primarily responsible for payment of bills. A Customer includes anyone taking Delivery Service or combined Electric Supply & Delivery Service from the Company under one service classification for one account,* *premise, or site. Multiple premises or sites under the same name are considered multiple Customers.*

2.1.6. ***Control Center*** *– The Company office that monitors and has direct control over the operation of the PHI Power Delivery System. It is divided into two parts, one controlling transmission assets and one controlling the distribution assets.*

2.1.7. ***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.*

2.1.8. ***Distribution Utility Utility Required Profile (DU-****URP) – Default Smart Inverter settings for DERs equal to or less than 250kVA.*

2.1.9. ***DER Overlimit Scheme –****Overvoltage protection on substation transformer high side terminals that trips downstream distribution feeders in the event of high voltages. This is a mitigation for ground fault overvoltages on transmission network due to reverse power from DER.*

2.1.10. ***Electric power system (EPS) –*** *Facilities that deliver electric power to a load. (Excerpted from IEEE Std 1547™-2018.)*

2.1.11. ***Facility*** *(or* ***Facilities****) – The Customer owned generating equipment and all associated or ancillary equipment, including Interconnection Equipment, on the Customer's side of the Point of Common Coupling (Point of Interconnection).*

2.1.12. ***Feeder Terminal*** *– Origin of the feeder. Encompasses the breaker, relaying, monitoring, and control, typically in the originating substation. Note that, where feeders are supplied by two substations, the feeder would have two feeder terminals.*

2.1.13. ***FERC*** *– The* ***Federal Energy Regulatory Commission*** *is the United States federal agency that regulates the transmission and wholesale sale of electricity and natural gas in interstate commerce and regulates the transportation of oil by pipeline in interstate commerce.*

2.1.14. ***Generator Owner*** *– The owner of the generation Facility that is interconnected to the Company.*

2.1.15. ***Grid*** *– The interconnected arrangement of generators, lines, transformers and other Utility equipment that make up the electric power system.*

2.1.16. ***Interconnection –*** *The result of the process of adding DER to an Area EPS, whether directly or via intermediate Local EPS facilities. (Excerpted from IEEE Std 1547™-2018.)*

2.1.17. ***Interconnection Agreement(s)** – Any contract between two or more parties that outlines and governs the interconnection requirements of a generation facility, including, but not limited to Interconnection Service Agreements (ISAs), standard two-party Interconnection Agreements (IAs), and state template agreements to interconnect DERs connecting under state programs such as NEM or other programs.*

2.1.18. ***Interconnection Application** –The request for generation at a new facility or additional generation at an existing facility. PHI makes the appropriate standard forms of the Interconnection Applications available on the customer facing websites of each of the utilities. The applications and required documentation were developed in conjunction with the presiding body of the applicable state or jurisdiction. These forms were prepared in contract form to be used as Interconnection Agreements once approved. The information provided is used to determine the impact of the generation on the PHI Power Delivery System.*

2.1.19. ***Interconnection Request –** The application for the interconnection of generation within the PJM footprint as administered by PJM and further defined in PJM Manual 14A: Generation and Transmission Interconnection Process.*

2.1.20. ***Interconnection Equipment** - That equipment necessary to safely interconnect the Facility to the PHI Power Delivery System, including all relaying, interrupting devices, metering or communication equipment needed to protect the Facility and the PHI Power Delivery System and to control and safely operate the Facility in parallel with the PHI Power Delivery System.*

2.1.21. ***Interface (Isolation) Transformer** - A transformer which interconnects a privately-owned generation source voltage with the PHI Power Delivery System voltage.*

2.1.22. ***Interoperability –** The capability of two or more networks, systems, devices, applications, or components to externally exchange and readily use information securely and effectively. (Excerpted from IEEE Std 2030™)*

2.1.23. ***Interval Metering** – The metering equipment that measures consumed and exported energy, in quantities such as kWh and kVARh, in defined intervals.*

2.1.24. ***NEM** – **N**et **E**nergy **M**etering - An electric tariff or rider that allows a customer DER to generate energy in excess of the demand of the facility at some periods of time and to credit the reverse energy flow against the overall facility energy use over the month or year. Maximum generation size and acceptable fuel source are dictated by the various State jurisdictions.*

2.1.25. ***NERC** - **N**orth American **E**lectric **R**eliability **C**orporation. A nonprofit corporation designated by FERC as the Electric Reliability Organization (ERO) for the contiguous United States. Canadian provinces bordering the United States also take part in NERC. The purpose of NERC is to ensure the adequacy, reliability, and security of the bulk electric supply systems through coordinated operations and planning of generation and transmission facilities.*

2.1.26. ***Parallel Operation*** *– Any DER operating with an electrical connection between the PHI Power Delivery System and the Generator Owner's generation source.*

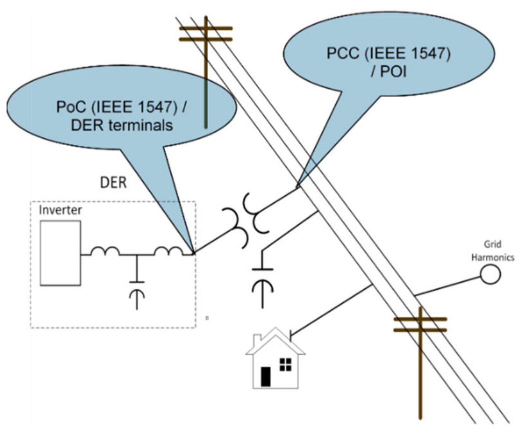
2.1.27. ***PHI Power Delivery System*** *– The electric system of the appropriate affiliate of PHI, i.e. either Atlantic City Electric, Delmarva Power & Light or Potomac Electric Power Company in whose geographic service area the Customer's Facility is electrically connected. This should include all that affiliate's electric facilities and systems located on that affiliate's side of the Point of Common Coupling including that affiliate's transmission and distribution systems.*

2.1.28. ***PJM*** *– PJM Interconnection, L.L.C. PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 States and the District of Columbia. Members include electric utilities and independently owned generating resources. The organization is responsible for dispatching generation, operating the bulk transmission system within its service area, and operating a buy/sell market for member's generation.*

2.1.29. ***PJM Operating Agreement*** *– That agreement dated as of April 1, 1997 and as amended and restated as of June 2, 1997 and as amended from time to time thereafter, among the members of the PJM Interconnection, L.L.C.*

2.1.30. ***PJM Tariff, PJM Transmission Tariff, or OATT*** *– The "PJM Open Access Transmission Tariff."*

2.1.31. ***Point of Common Coupling (PCC)*** *– The point where PHI service connects with the DER plant. This is usually the point of interconnection (POI). (Excerpted from IEEE Std 1547™-2018.)*



2.1.32. ***Point of Connection (PoC)*** *– The point where the DER is connected to the plant electric power system. (Excerpted from IEEE Std 1547™-2018.)*

2.1.33. ***Point of Interconnection (POI)*** *– Point where the customer system interconnects with the Utility grid. It is the demarcation point between customer owned equipment and Utility owned equipment. Typically, the same as the PCC.*

2.1.34. ***Pre-Interconnection Study** – A technical study or studies performed to identify actions required to allow DER to be interconnected to the grid. These studies are prepared in response to the Interconnection Application or, in the case of PJM projects, the Interconnection Request. Pre-Interconnection Studies may include, but are not limited to, service studies, coordination studies and facility impact studies.*

2.1.35. ***ReliabilityFirst (RF)** – One of eight Regional Reliability Councils which together form the North American Electric Reliability Corporation (NERC). RF is responsible for thirteen States and the District of Columbia including all the PHI service territories in Delaware, Maryland, New Jersey, Virginia and Washington, DC.*

2.1.36. ***RTU** (**R**emote **T**erminal **U**nit) – The remote unit of a supervisory control system used to telemeter operating data, provide device status/alarms and to provide remote control of equipment at a substation or generator site. The unit communicates with a master unit at the PHI Control Center.*

2.1.37. ***Reference Point of Applicability (RPA)** – The reference point of applicability for any requirement varies and can be at the Point of Connection (PoC) or Point of Common Coupling (PCC), or either. DER Requirements of this document apply to the RPA. (Excerpted from IEEE Std 1547™-2018; the location concept is defined in Clause 4.2.)*

2.1.38. ***Stabilized** – The state of the Company's system when the voltage and frequency have returned to their normal range for at least 5 minutes following a disturbance. If tripped, Customer owned generation may reconnect to the PHI Power Delivery System. The Company may require a longer time upon a reasonable showing that reconnection after only 5 minutes will adversely impact the safety and reliability of the PHI Power Delivery System.*

2.1.39. ***Stiffness Ratio** – A measure of how strong a generator's fault current contribution is in comparison to the total fault current available at the Point of Common Coupling. Stiffness Ratio = Total Fault Current Available at PCC (MVA)/Generator Fault Contribution (MVA).*

2.1.40. ***System Emergency** -- An imminent or occurring condition on the PHI Power Delivery System, the PJM System, the system of a neighboring Utility, or in the Facility that is likely to impair system reliability, quality of service, or result in significant disruption of service, or damage, to any of the foregoing, or is likely to endanger life, property or the environment.*

2.1.41. ***Telemetry** – The process of recording and transmitting the readings of an instrument. For example, collection of measurements or other data at remote or inaccessible points and their automatic transmission to receiving equipment for monitoring. In the case of DERs, applications include telemetry for protection device status, for power flows, for settings, and for other plant or related Utility equipment condition status.*

2.1.42. ***Large DER** –DER interconnecting with application size greater and equal than 1000KW for 34KV nominal voltage, 500KW for 25KV nominal voltage, 250KW for less than 24KV nominal voltage.*

2.1.43. ***Flexible Interconnection (FI) –*** *means an interconnection process to downsize an interconnection by providing an interconnection customer a scheduled real power output export to follow over a specified time frame. At PHI, the specified time frame is the entire year.*

2.1.44. ***Limited Export Agreement (LEA) -*** *means an agreement for energy supplied to the grid by an interconnection customer that may be managed to specified ramp rates and generation levels for operating conditions, as specified in the interconnection agreement or in a separate limited export agreement. The LEA is applicable over a an entire year's time frame.*

2.1.45. ***Power Control Systems (PCS)*** *– Systems or devices which electronically limit or control the steady state AC currents or DC currents, to a programmable limit or level.*

2.1.46. ***PCS Controller*** *– The control element within a PCS that executes the control logic.*

2.1.47. ***Export Limit*** *– The programmable limit in a power control system (PCS) real power or kilo-watts. This export limit is determined by conducting static power flow analysis and/or time series power flow analysis.*

2.1.48. ***Open Loop Response Time (OLRT)*** *– the duration between a control signal input step change (reference value or system parameter) until the controlled output changes by 90% of it's final change, before any overshoot.*

2.1.49. ***AC EVSE -*** *means supply equipment that passes alternating current to the EV with conversion between AC and DC accomplished onboard the EV.*

2.1.50. ***DC EVSE -*** *means supply equipment that passes direct current to or from the EV, with the EVSE accomplishing conversion between AC and DC.*

2.1.51. ***Electric vehicle supply equipment" or "EVSE"*** *- means a device or system designed and used specifically to transfer electrical energy between an electric vehicle and the electric grid.*

2.1.52. ***V2G or Vehicle To Grid -*** *means the ability for an EVSE connected to a bidirectional electric vehicle to operate in parallel to the grid and both receive and feed power to the point of interconnection between the EVSE and the grid.*

2.1.53. ***V2G System -*** *is a combination of hardware and software in or around the EVSE and EV for the purposes of communication with and programmed flow of energy into and out of the vehicle battery in support of electrical loads or systems offboard the EV, including the electric grid.*

2.1.54. ***Bidirectional electric vehicle -*** *means an electric vehicle that is capable of both receiving and discharging electricity.*

2.2. Acronyms

ACR – Automatic Circuit Recloser

DA – Distribution Automation

DER – Distributed Energy Resource

EMI – Electromagnetic Interference

EPS – Electric Power System

ESS – Energy Storage System

IC – Interconnecting Customer

LVAC – Low Voltage AC

OpCos – Operating Companies of Exelon includes BGE, ComEd, PECO, and PHI

PoC – Point of Connection

PCC – Point of Common Coupling

PHI - Pepco Holdings

POI – Point of Interconnection

RPA – Reference Point of Applicability

TIR – Technical Interconnection Requirements

3. General Review Requirements

3.1. Criteria for DER Interconnection

All DER interconnections will be evaluated for the following:

- Safety of the public or Utility personnel
- Risk of degradation to services for customers due to interruptions or power quality events
- Compromise of security or reliability of Utility electrical systems
- Applicability of DER size or primary source to the state or PJM requirements.

All developers and owners of approved DER interconnections are required to be responsive to the Utility's direction and instructions during emergency conditions or to remove the DER from service when the Utility is performing line maintenance or other work on the circuit to which the DER is connected.

3.2. Application Technical Review Process

Guidelines for processing applications to interconnect DER and the related technical reviews are specified by state, district, or PJM jurisdictions that PHI serves. Details of the process depend on the complexity of the DER to be connected. Each state has provided different DER application levels, which are defined by size, point of connection, DER type, and operating characteristics. The state specified levels define procedures and considerations of the technical review process. All connections to be operated in parallel with the electric grid are subject to technical review. The applicable regulations in the PHI service territory are as follows:

- Delaware: Delaware Code "Title 26 – Public Utilities" and Delmarva Interconnection Standards
- Maryland: Maryland Public Service Commission Title 20, Subtitle 50 "Service Supplied by Electric Companies", Chapter 9 "Small Generator Interconnection Standards"
- New Jersey: New Jersey Administrative Code Title 14 "Public Utilities", Chapter 8 "Renewable Energy and Energy Efficiency", Subchapter 5 "Interconnection of Class I Renewable Energy Systems"
- Washington, D.C.: D.C. Municipal Regulations Title 15 "Public Utilities and Cable Television", Chapter 15-40 "District of Columbia Small Generator Interconnection Rules"
- PJM Manual 14G – "Generator Interconnection Requests"

Technical review of each interconnection application shall be made to ensure that operation of the proposed DER system is consistent with the technical requirements of the power delivery system and does not adversely impact other customers. Existing PHI technical guidelines for interconnecting generation to the grid include but are not limited to: PHI Technical Interconnection Requirements for Parallel Interconnection of DER Document, applicable state Rules, technical interconnection standards and local codes. For large independent power producers there are also Federal Energy Regulatory Commission (FERC) Rules, North American Reliability Commission (NERC) Standards and PJM Interconnection Inc. (PJM) requirements that may apply.

The general principles of these interconnection requirements, as considered in this document, are:

- DER interconnection and operation shall not compromise the safety of the public or Utility personnel.
- DER interconnection shall not degrade service to any customers by causing interruptions or power quality events.
- DER interconnection shall not compromise the security or reliability of Utility electrical systems.
- DER owner shall be responsive to Utility direction during defined emergency conditions or to requests to remove the DER from service when the Utility is performing work on the circuit to which the DER is connected.
- Cost of the DER interconnections shall be clearly defined and borne by the owner/operator/installer or shared with customers as mandated by state laws, rules or regulations, the PJM manual and/or applicable Utility tariff requirements.

4. DER Technologies

4.1. Inverters

Based on applicable state laws and regulations and distribution system characteristics, inverter-based generators shall utilize equipment with advanced functionality, otherwise known as "smart inverters." At a minimum, smart inverters have the following functionalities and capabilities:

- Frequency and voltage-disturbance ride through
- Ramp rate control
- SCADA communications
- Curtailment or other mitigation ability if high voltage were to occur
- Ability to receive and respond to a trip signal
- Ability to adjust PF or VARs based on Utility signal
- Ability to adjust Real Power Output based on Utility signal
- Ability to set and adjust Volt/VAR and Volt/Watt curves to provide grid support or avoid grid violations
- Anti-Islanding capability

Inverters shall be UL 1741 SB certified as "Grid Support Interactive Inverter" or "Grid Support Utility Interactive Inverter" installed or commissioned with the IEEE Std 1547™-2018 specified performance capabilities. Unless specified otherwise, all grid support functions shall be initially disabled.

These requirements and functionalities are already specified in IEEE Std 1547™-2018 for all future DERs and shall be required when product is available and as specified by state or PJM rules or tariffs.

Unless stated otherwise during technical review, DERs equal to or less than 250 kVA shall use default settings depicted in the PHI distribution utility required profile (DU-URP) (See Appendix

H).[1][2][3] Site specific settings will be determined during technical review for DERs greater than 250 kVA.

Specific settings within the plant capability may be required at the time of installation or later if conditions change. Within the conditions of the interconnection agreement, PHI may need to control the DER through communication devices. This includes communication interoperability that may be used to update specific functions and settings.

Other inverter requirements include:

- To address steady state high voltage on the circuit due to output from a DER, the Utility may require the DER to reduce power output when grid voltage goes above ANSI limits.
- Where an ACR has been installed, the Utility may monitor voltage at the ACR and disconnect the DER facility by opening the ACR, for high voltage.
- DERs utilizing inverters may wish to consider oversizing the inverters slightly to reduce impact on real power output if/when they export or import VARs to maintain proper voltage.

Facilities required to implement Dynamic VAR compensation, shall have the capability of dynamically compensating for power fluctuations to mitigate the change in voltage at the Point of Common Coupling. Voltage changes due to power output fluctuations shall be kept in compliance with IEEE Std 1547™-2018 requirements. The systems must be able to perform dynamic control in addition to steady state voltage control described above.

For purposes of fault analysis, the fault current from a distribution inverter based resource (2 cycles and longer) may be estimated using 120% of AC nameplate.

4.2. Synchronous Generators

For Synchronous Generators, the generator may be required to operate in a mode that mitigates high voltage during low load periods such as operating the generator at a leading power factor and thus absorbing VARs to limit the local high voltage.

Protection schemes must be designed to ensure detection of fault conditions on the PHI system.

4.3. Battery Storage

Evaluation of DER Battery Energy Storage Systems (ESS) will be based on the application, feeder operation and the customer planned ESS operating mode. Interconnection considerations will include reverse power under maximum discharge (exporting) at minimum load and the maximum charging power (importing) at the maximum load condition. If used in conjunction with generation, the impact of running both at the same time must be studied.

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[1] DU-URP settings are described in Appendix F. Unless stated otherwise, the default function status and settings in IEEE 1547-2018 are applicable.

[2] DU-URP settings may be on file with state Public Service Commissions and other AHJs. Any changes shall be subjected to utility counsel review.

[3] Reference COMAR § 20.50.09.06(O) and DCMR §4002.7. Note: New Jersey and Delaware regulations suggest the use of latest 1547 revision and do not specify the need for approval of default settings

ESS systems have several different potential operating modes. Modes that export power include local grid support (including frequency regulation) and energy arbitrage such as daytime/nighttime. Non-exporting modes include self-consumption of generation such as solar PV, backup power, and load shifting/demand management.

Systems intended to operate in a frequency regulation mode may have additional requirements because of rapid change from charge to discharge with potential to cause voltage regulation issues. When evaluating ESS that are responding to a frequency regulation signal, it is assumed they act in unison and the aggregate capacity will be used to assess the maximum impact on the circuit. Voltage rise/drop, and fluctuation are limited based on the circuit, DER location and related standards including IEEE Std 1547™-2018.

For behind-the-meter applications where the battery never exports while in parallel with the grid and both the battery and the solar system share one inverter, no additional metering or monitoring equipment shall be required for a solar-plus-storage facility than would be required for a solar facility without storage technology.

4.4. *V2G Vehicle to Grid –*

Electric vehicles (EVs) have on-board energy storage (ES) systems that may have the capability of modulating charging and exporting power to the electric power system (EPS). EVs can connect directly to an ac system through an EV charging station (e.g., electric vehicle supply equipment [EVSE]) with the ES on-board inverter located on the EV. EVs may also have a dc port where they would be connected to an inverter located external to the EV to charge or discharge the on-board ES. The inverter, whether on-board or off-board, can be either unidirectional or bidirectional. Off-board inverters are required to meet applicable Underwriters Laboratory (UL) standards in either mode. If the inverter is bidirectional and is able to connect to the EPS, whether located on-board or off-board, it shall comply with IEEE Std 1547. Off-board bidirectional inverters may also be used in Local EPS islands (i.e., facility islands) to supplement the island energy requirement or in stand-alone generation modes where they regulate the voltage and frequency for power delivered to connected loads. Both ac and dc systems that are capable of power export should incorporate IEEE 1547 performance Category B in Clause 5 [1547] and Category III in Clause 6 [1547].

V2G systems, while similar to exporting battery energy storage, have several unique considerations worthy of discussion. There are two types of V2G bi-directional charging technologies: AC EVSE and DC EVSE types. The primary difference between AC and DC types is where the AC-DC power conversion equipment is located. PHI accepts both types of EVSE on it's electrical grid, granted the V2G adheres to the proper standards and certification outlined below.

DC EVSE – the inverter is located inside the EVSE and the EVSE or inverter inside the EVSE must have UL-1741-SB certification.

AC EVSE shall be certified via two pathways

Pathway 1 – the EVSE shall be certified to UL-2594 & UL-1741 and the inverter located in the bi-directional vehicle shall be certified to SAE J3072.

Pathway 2 –the EVSE shall be certified to UL-9741 and the inverter located inside the bidirectional vehicle shall be certified to UL-1741-SB under the QIKP grid interconnection performance certification.

Furthermore, V2G interconnection shall be valid only at a single point of interconnection, V2G systems shall be evaluated using the same process's as battery energy storage, and V2G systems shall not be authorized in bidirectional mode while in parallel operation with the local electric power system unless an interconnection agreement is in place between the interconnection customer and the relevant electric utility and the interconnection customer has received a permission to operate from the electric company.

SAE International (SAE) is a global association of engineers and related technical experts in the aerospace, automotive, and commercial-vehicle industries. One of its core competencies is consensus standards development. SAE defines the interface (mechanical, electrical, and communication) standards on vehicles and between EVs and the EPS. SAE relies on standard bodies such as the IEEE Standards Association and International Electrotechnical Commission (IEC) to verify that vehicle equipment that interfaces to the EPS complies with internationally recognized standards, e.g., inverters that interface to the EPS and are capable of exporting active power should comply with IEEE Std 1547 and IEEE Std 2030.5 (SEP2) [B26].

SAE publishes Standard J3072 [B47] for bidirectional onboard inverters that connect to the EPS. SAE J3072 requires conformance to IEEE Std 1547-2018 and IEEE Std 1547.1-2020 as Category B and Category III. Because the EV inverter is a distributed, embedded function of the electric vehicle and not a self-contained device, a core element of the SAE standard is the process by which the vehicle manufacturer identifies and controls the configuration of the core hardware, software, and firmware components that constitute the inverter function and assigns a unique Inverter System Model Number (ISMN). The electric vehicle supply equipment (EVSE) serves as the primary DER Managing Entity (DME) for the connected EV. The EVSE uses upstream communication with DER management entities to receive local settings for IEEE 1547-2018 functions. The EVSE also uses the local communication with the EV to send the local DER settings to the EV and to exchange information such as nameplate ratings, configuration setting, monitored data, and management information with the connected EV, as defined by IEEE Std 1547 and IEEE Std 1547.1. See Figure B.1 for a system concept diagram and Figure B.2 for protocol control mapping. The DME is the Distributed Energy Resource Managing Entity as defined in IEEE Std 1547, and ISE is a term defined by UL as interconnection system equipment.

SAE-defined smart charging use cases in SAE Information Report J2836/3 [B44] are shown in Figure B.3. Smart charging is referred to as V1G, and bidirectional exportable vehicle power is defined as vehicle to grid (V2G). SAE Use Case U6 was adopted by EPRI in its report "Common Functions for Smart Inverters" [B4] as "Energy Storage: Coordinated Charge/Discharge Management Function." IEC 61850-7-420 [B13] included this use case as "Coordinated Charge/Discharge Operational Function." This function is required

SAE J3072 to be implemented for onboard inverters (V2G-AC). It is expected that these functions will be implemented in the EVSE for off-board inverter systems (V2G-DC). SAE intended Use Case U7 to include all the V2G inverter functions defined by IEEE Std 1547 and was based on the EPRI report and IEC 61850- 90-7. Use case U5 and U6 apply to both V1G and V2G with the reverse power flow only applying to the V2G function. In addition to the SAE standards, the ISO/IEC 15118 communication series of standards, IEC 63110 protocol for management of EV charging and discharging, and draft IEC 63382 management of distributed energy storage systems based on EV also provide standards for EV and EPS interaction including EV as a DER.

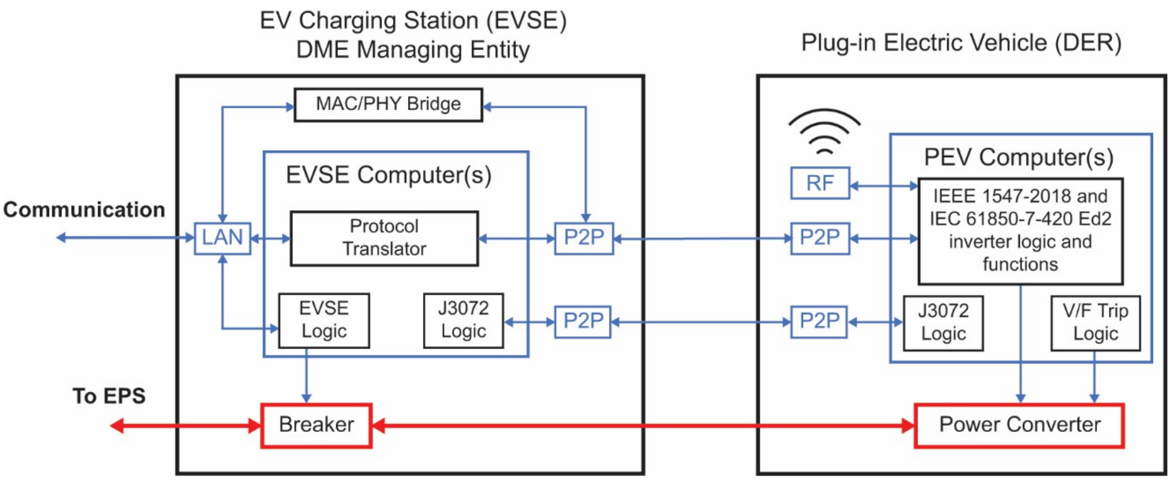
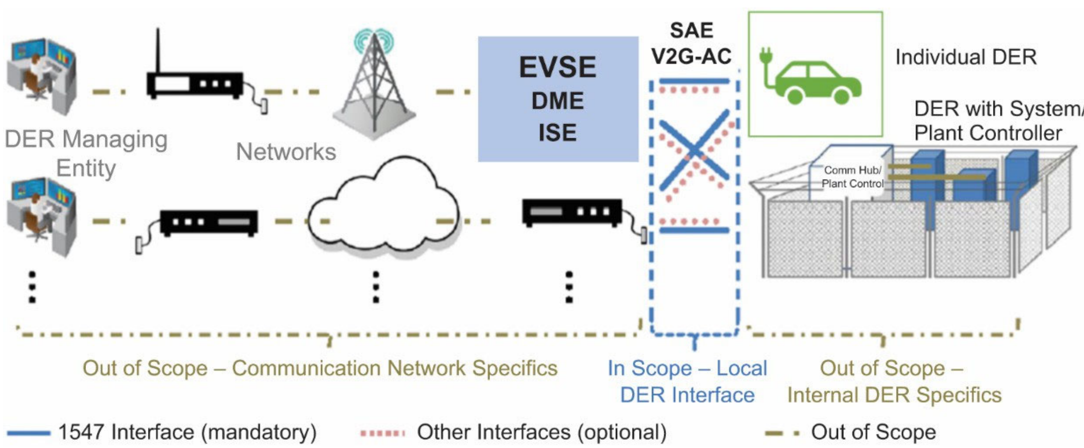


Figure J3072 system diagram for V2G-AC plug-in electric vehicle (PEV)



Smart/Optimized Charging (V1G)

DER (V2G)

SAE Use Cases	Type	Reverse Power Flow	Reactive Power
U1: Time of Use	Price		
U2: Demand Response	Stop		
U3: Real-Time Pricing	Price		
U4: Critical Peak Pricing	Price		
U5: Flow Reservation	Fixed	Yes	
U6: Basic DER Fixed Flow	Fixed	Yes	
U7: Advanced DER: Fixed PF	Fixed	Yes	Yes
U7: Advanced DER: Fixed VAR	Fixed	Yes	Yes
U7: Advanced DER: Freq-Watt	Auto	Yes	
U7: Advanced DER: Volt-Watt	Auto	Yes	
U7: Advanced DER: Volt-VAR	Auto	Yes	Yes
U7: Advanced DER: Watt-PF	Auto	Yes	Yes
U7: Advanced DER: H/L FRT	Limit	Yes	
U7: Advanced DER: H/L VRT	Limit	Yes	

4.5. Power Control Systems (PCS) and PCS Controllers

The industry standard for governing the behavior of a power control system is “certification requirement decision” (CRD) called UL-1741-CRD for PCS. This certification document will eventually be replaced with UL-3141 which will be an industry certification manufacturers can use to certify on their equipment. The CRD determines the performance and testing requirements for certifying a PCS to UL-1741 standards.

A PCS can be a fully integrated system or it can be a system compromising of multiple discrete components built by different manufacturers. The overall goal of any PCS is to limit the power at the point of common coupling with the utility to prevent impacts to the distribution grid. These impacts can be itemized into: steady state and transient impacts identified by PHI engineers. Supplemental utility grade relaying may be required in addition to the PCS system to limit the export of real, and/or reactive power into the PHI Power Delivery System.

While the PCS technology limits the export at the PCC with the utility, legal agreement contracts are still required. The limited export agreement (LEA) must be signed by the customer and Pepco Holdings to ensure the DER legally agrees to not export more real power than the export limitation. The PCS and the respective PCS controller shall be programmed to limit the export to the amount stipulated in the LEA.

The PCS can be AC or DC coupled. Depictions of AC and DC coupled PCS systems are shown in figure A.1/A.2 and should be depicted on the DER site’s single line diagram provided by the customer.

UL-1741-CRD for PCS outlines PCS requirements in detail; to highlight the key parameters of PCS:

The PCS system must control the output of DERs (Batteries, Solar Inverters, Controllable Loads, etc) such that the export of power or current at the PCC is limited to an agreed amount of KW, KVAR or both.

The PCS system monitors analog input signals from the PCC to achieve this control objective such as MW/MVAR/Amperes/etc.

When these inputs signals change such that the limited export objective is no longer met, the PCS must be capable of controlling the output of DERs (Batteries, Solar Inverters, Controllable Loads, etc) such that 90% of the final change the controlled export value is achieved within the open loop response time (OLRT) of the PCS.

The OLRT is typically 2 – 30 seconds and set to 30 seconds by default.

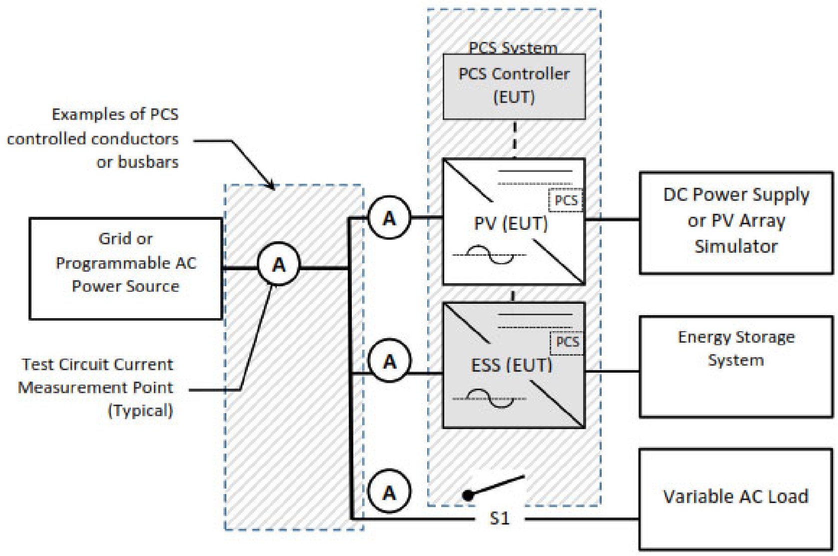


Figure A.1 – AC Coupled PCS System, UL1741CRD for PCS, pg.5

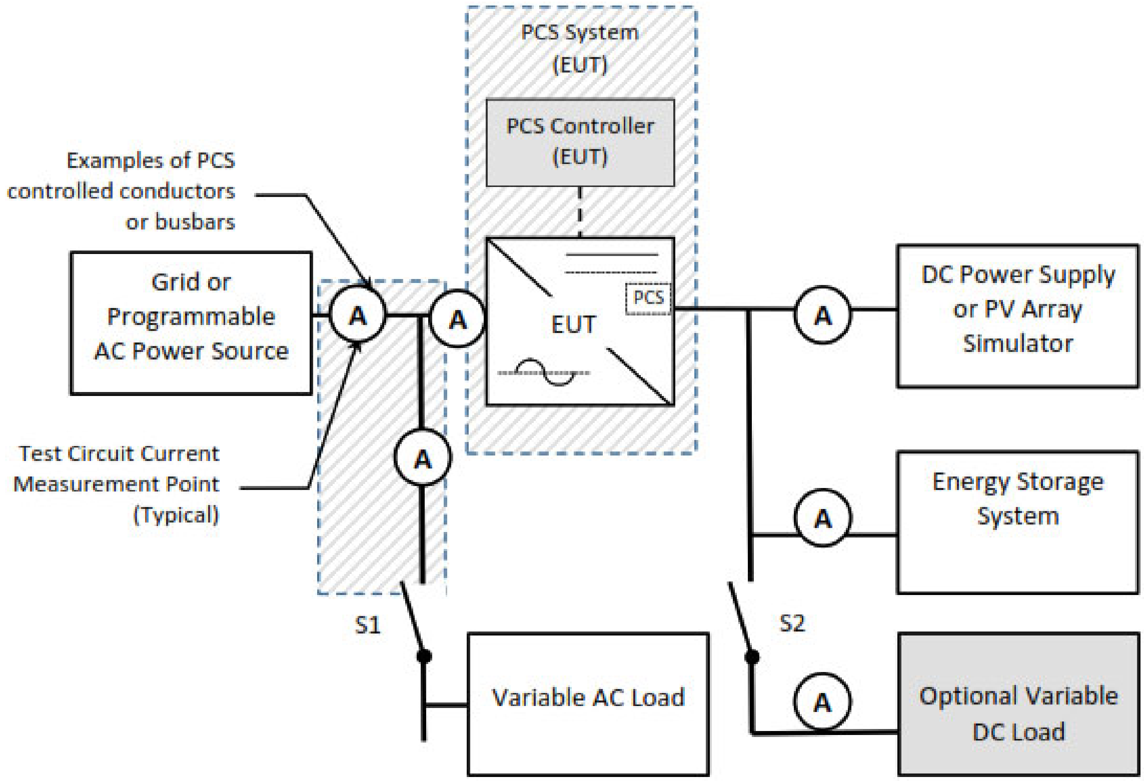


Figure A.2 – DC Coupled PCS System, UL1741CRD for PCS, pg.6

The above diagrams of PCS depict generic systems but in practice the PCS controller may or may not be integrated into a single hardware device. For example, at PCS could be three discrete components such as a solar inverter, a battery inverter and an RTAC automation controller or a single discrete component where a manufacturer has integrated the three devices into a single component. In cases where an export limit is dynamically changing with time, utility control over the export limit is required.

4.6. Induction Generators

Customers shall be required to install mitigating equipment in cases where induction generators for intermittent sources cause voltage or reactive current issues. Customer or Utility power factor correction capacitors near an induction generator site can increase the probability of self-excitation of the generator when isolated from the grid. This can result in abnormally high voltages and will require protection.

5. General Technical Requirements

These requirements are applicable at the Reference Point of Applicability. This can be either the PCC or PoC, or both, depending on several parameters including DER size, percent of local load demand, and related protection coordination. Requirements that depend on external exchange of inputs —such as between two or more networks, systems, devices, applications, or components — need to be interoperable and, able to exchange and readily use information securely and effectively.

5.1. Applicable Voltages

The applicable voltages determine the performance of a Local EPS or DER and are the electrical quantities specified about the reference point of applicability, individual phase-to-neutral, phase-to-ground, or phase-to-phase combination and time resolution.

5.1.1. Medium-Voltage Connections:

For DER with a PCC located at the medium-voltage level, the applicable voltages shall be determined by the configuration and nominal voltage of the Area EPS at the PCC.

5.1.2. Low-Voltage Connections:

For DERs with a PCC located at the low-voltage level, the applicable voltages shall be determined by the configuration of the low-voltage winding of the power transformer(s) between the medium-voltage system and the low-voltage system. The applicable voltages that shall be detected are shown in Table 1 and Table 2. For multi-phase systems, the requirements for applicable voltages shall apply to all phases.

Table 1 – Applicable voltages when PCC is located at medium voltage

DER Connection at PCC	Applicable voltages
Three-Phase, Four-Wire	Phase-to-phase and phase-to-neutral
Three-Phase, Three-Wire	Grounded Phase-to-phase and phase-to-ground
Three-Phase, Three-Wire	Ungrounded Phase-to-phase
Single-Phase, Two-Wire	Phase-to-2nd wire (the 2nd wire may be either a neutral or a 2nd phase)

Table 2 – Applicable voltages when PCC is located at low voltage

Low-voltage winding configuration of Area EPS transformer(s)[a]	Applicable voltages
Grounded Wye, Tee, or Zig-Zag[b]	Phase-to-phase and phase-to-neutral, or Phase-to-phase and phase-to-ground
Ungrounded Wye, Tee, or Zig-Zag	Phase-to-phase or phase-to-neutral
Delta[c]	Phase-to-phase
Single-Phase 120/240 V (split-phase or Edison connection)	Line-to-neutral—for 120 V DER units Line-to-line—for 240 V DER units[d]

[a] A three-phase transformer or a bank of single-phase transformers may be used for three-phase systems.

[b] For 120/208 V two-phase services, line-to-line voltages shall be sufficient.

[c] Including delta with mid tap connection (grounded or ungrounded).

[d] Sensing line-to-neutral on both legs of a 120/240 V split-phase or Edison connection effectively senses the line-to-line and is therefore compliant with this requirement. Sensing line-to-ground may also be used; however, the ground connection should only be used for voltage sensing purposes.

The DER shall not cause the delivery voltage levels on the PHI distribution system to deviate outside of the range of voltages described by ANSI C84.1, Electric Power Systems and Equipment, or in the applicable state regulation, if it is different than ANSI.

DER interconnections may require a 3-phase connection depending on size. If three-phase service is available, it is preferred for most systems larger than 25 kW and is required for any system 100 kW or greater. All 3 phase systems shall operate with balanced output on each phase under normal operating conditions.

The highest and lowest allowable steady state delivery voltages for PHI (on a 120 V base) are:

Utility	Highest Voltage	Lowest Voltage		Notes
		Primary	Meter	
PHI	126 V	117.5 V[2]	114 V	CVR (MD Only)[1]

[1] Conservation by Voltage Reduction ("CVR") implemented to reduce energy use by lowering voltage.

[2] This is a self-imposed limit in Maryland to align with other PHI utilities.

Additional requirements for applicable voltages are specified in IEEE Std 1547™-2018 clause 4.3 - Applicable Voltages. These requirements include phase-to-phase, phase-neutral and phase-to-ground configurations, the standard also identifies requirements where the DER does not measure individual phase voltages and requirements for determining applicable voltages for low and high voltage ride-through.

5.2. Existing Service Transformer Connections

Low voltage DER connections are normally via an existing PHI load service transformer. Larger plants may require either an upgrade of the PHI service transformer or the addition of a customer owned DER plant service transformer.

5.2.1. Distribution Service Transformer Capacity

There are size limits for the transformer relative to the DER. The following size considerations shall apply to determine when a DER interconnection application requires a service transformer upgrade:

- If the aggregate DER output is greater than the transformer nameplate rating plus 0.5 kW x all residential premises connected to that transformer and 10% times all commercial customers peak load (or actual minimum day time load) tied to the transformer, it shall be replaced.
- When voltage-rise associated with DER power back feed is anticipated the service transformer may need to be upgraded to maintain voltage with standard limits.

5.2.2. New or Replacement Customer Owned Transformer Configuration Requirement

The following winding configuration requirements shall apply where a DER interconnection application requires a customer *owned* transformer replacement or an additional customer owned transformer:

Permitted	Pepco	ACE/DPL
Conditionally Acceptable	Grounded Wye / Grounded Wye[1]	Grounded Wye / Grounded Wye[1]
	Delta / Grounded Wye[2]	Delta / Grounded Wye[2]
		Delta / Delta[2]
Unacceptable[3]	Grounded Wye / Delta[1]	Grounded Wye / Delta[1]
	Delta / Delta[2]	

Note: the winding listed first is facing the utility (i.e. utility/customer)

[1] This transformer option may impact the MV protection coordination and require review and potential modifications to settings. PHI requires that customers install only 5 core (shell type) transformers if a grounded wye is facing the utility medium voltage side.

[2] Requires three phase overvoltage protection on the utility side of the transformer to trip off the generation. Overvoltage settings must coordinate with utility equipment temporary overvoltage withstand.

[3] These winding configurations are not acceptable for new or replacement transformers. Existing transformers will not require replacement as part of the interconnection process.

- Three-phase DER systems shall not be connected to Open Wye-Open Delta banks. Single phase DER systems must only be connected to Open Wye-Open Delta banks if they are connected to the larger transformer (lighting) and are less than 20% of the capacity of that transformer and create less than 20% unbalance.
- In areas where a voltage level is being retired, the developer will be required to use a dual voltage transformer and associated equipment rated to operate at the higher voltage level, so that when a conversion takes place, the transformer will support the new voltage level.

- For large projects connecting to the primary, especially on an express circuit, the developer shall be advised to use a transformer with no load taps (+/- 2.5 and 5% typically).

5.2.3. Basic Insulation Levels (BIL)

Rating of any new transformer must coordinate with the requirements of the Utility system at the PCC. All customer equipment should be designed to the BIL rating of the Utility line to which it is being interconnected.

5.3. Effective Grounding

The DER interconnection (inclusive of DER assets and interconnecting transformer) must be compatible with the feeder grounding practice at the Point of Interconnection. With some exceptions, installations should meet the requirements for "effectively grounded" as described in IEEE/ANSI C62.92.2 for synchronous machines and C62.92.6 for inverters. Effective grounding is also a requirement specified in IEEE Std 1547™-2018 clause 4.12 - Integration with Area EPS Grounding.

- In the case of synchronous machine generation, the zero-sequence impedance needs to be at least equal to the positive sequence impedance and continuous through the transformer.
- In case of inverter DER grounding requirements depend on the circumstances.

5.4. Open-phase Detection

The DER shall detect and cease to energize and trip all phases to which the DER is connected for any open phase condition occurring directly at the reference point of applicability per 4.2 and the applicable voltages per 4.3. The DER shall cease to energize and trip within 2.0 seconds of the open phase condition. The design and implementation of the interconnection shall eliminate the potential for ferro-resonance.

5.5. Cease to Energize

DER cease to energize performance requirements are specified in IEEE Std 1547™-2018 clause 4.5. Cease to energize is identified as “cessation of active power delivery.” This still allows for limited reactive power from passive devices. This function is specified in several DER response requirements.

5.6. Control Capability Requirements

The DER shall respond to external inputs that include tripping the unit, limiting active power, and executing mode or parameter changes. Any control capability will require telemetry. These capabilities need to be interoperable to exchange status and readily follow the external input.

Requirements are specified in IEEE Std 1547™-2018 clause 4.6. Limiting DER active power is normally to a maximum agreed set point, or in the case of DER combined with load, it may be the net export power including load variations. This normally allows up to 30 seconds of limited, inadvertent export that does not cause operating violations.

5.7. Prioritization of DER Responses

The priority or precedence of different DER response requirements to varying conditions are laid out in IEEE Std 1547™-2018 clause 4.7. These include disabling permit service, trip, ride-through, voltage-active power mode, active power limit and voltage regulation modes.

5.8. Isolation Device

Customers are required to install an approved device for all interconnections for isolating the DER from the Utility's distribution system. For customers with DER systems larger than 50KW or where operation of the switch could create safety concern for PHI personal[4] the device shall be readily accessible by the utility, have a physical disconnect with a visible break capable of interrupting full load current and be lockable and taggable in an open position.[5] These requirements incorporate requirements in IEEE Std 1547™-2018 clause 4.8 - Isolation Device. For all other DER systems not covered by the previous requirement, the national electric code and local jurisdictional interconnection rules apply.

	Isolation Device Utility Requirement				
Jurisdiction	*Lockable*	*Taggable*	*Visible Break*	*Utility Accessible*	*Open/Close Status Indicated*
New Jersey[6]	**NR**	**NR**	**NR**	**NR**	**NR**
Maryland[7]	**X**	-	**X**	**X**	**X**
Washington DC[8]	**X**	-	**	**X**	**X**
Delaware[9]	**X**	-	**	**X**	**X**

NR not required   ** 600V and greater
X Required in all Cases   - not specified

PHI requires the installation of a disconnect switch as defined above for all systems. An ACR shall be required for DER sizes over 1 MW if the system supplies no electric customer load other than DER station load. In that case, an acceptable disconnect that the Utility can access will be required. If remote trip or direct transfer trip are required, the isolating device shall be able to operate based on the respective signal. In cases where transfer trip is required and no ACR is installed, a customer circuit breaker may be required that is capable of locking out and isolating the customer generator from the utility.

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[4] Secondary services greater than 300 volts can cause electrical arcing when opened because of the higher voltage/amperage and therefore creates a safety concern for PHI personal operating the isolation device.

[5] There is no isolation device requirement in New Jersey rules; therefore, the utility will not require any switch in ACE. In Washington DC (Pepco) and Delaware (DPL), systems below 600V will be exempt from the 'visible break' requirement.

[6] New Jersey Admin Code §14:8-5.2 - General Interconnection Provisions

[7] COMAR §20.50.09.06 - General Requirements

[8] DCMR § 4008.10, 4008.11 – Technical Requirements

[9] Delaware Rules - Section 6 Part G

5.9. Inadvertent Energization of Area EPS

IEEE Std 1547™-2018 clause 4.9 - Inadvertent Energization of the Area EPS requires that the "DER shall not energize the Area EPS when the Area EPS is de-energized."

5.10. Enter Service

For DERs ≥250 kVA, ramp up of power output shall be limited so the voltage at the Point of Common Coupling will comply with the voltage requirements and to ensure existing regulation equipment can properly adjust. Ramp up should be 2 MW per minute or less on 12 – 13.8 kV circuits, 3 MW per minute or less on 23 - 25 kV circuits, and 5 MW per minute or less on 34 kV circuits.

For DERs <250 kVA requirements are specified in IEEE Std 1547™-2018 clause 4.10 - Enter Service. These include the allowable voltage and frequency ranges for entering service and performance during entering service. Settings include a delay to enter service of 300 seconds and a duration for entering service of 300 seconds applying a linear or stepwise linear ramp.

5.10.1. Synchronization

Requirements for synchronization are specified in IEEE Std 1547™-2018 clause 4.10.4 - Synchronization. These requirements provide maximum voltage step changes when synchronizing and synchronization parameter limits for different DER kVA.

5.11. DER Interconnection integrity

This section addresses immunity requirements of the DER to operate properly and safely in typical and expected grid environments. These DER certification requirements intend to promote electromagnetic compatibility of the DER with the electric grid and are covered in IEEE Std 1547™-2018 section 4.11.

5.11.1. Electromagnetic Interference

IEEE Std 1547™-2018 clause 4.11.1 - Protection from Electromagnetic Interference (EMI) identifies the DER immunity requirements for DER performance-critical controls and protections.

5.11.2. Surge Withstand

Voltage and current surge withstand requirements for the DER are specified in IEEE Std 1547™-2018 clause 4.11.2 - Surge Withstand Performance.

5.11.3. Paralleling device

Requirements for the paralleling device, including the requirement to withstand "220% of the DER rated voltage across the DER paralleling device," is specified in IEEE Std 1547™-2018 clause 4.11.3 - Paralleling Device.

6. DER Support of Grid Voltage

6.1. Reactive Power Capability

All DER installations will be required to have reactive power support capability. This means the individual DERs, or the DER systems (at PCC or plant level), shall be capable of injecting reactive power (over-excited) and absorbing reactive power (under excited). As specified in IEEE Std 1547™-2018, there are category A and B capability requirements as shown in Table 3.

Table 3 – Applicable Minimum reactive power injection and absorption capability

Category	Injection capability as % of rated apparent power (kVA)	Absorption capability as % of rated apparent power (kVA)
A (at DER rated voltage)	44	25
B (over the full extent of ANSI C84.1 range A)	44	44

For both categories A and B, the full kVAR minimum capability is required for active power output levels above 20% of rated power. For reduced real power output levels, from 5% to 20%, the DER % reactive power requirement is calculated by % active power/20% rated active power.

PHI Requirements:

- Inverter-connected DERs shall have Category B capability and will be initially set to volt-var mode per utility required profile in Appendix H. . Depending on PCC, DERs >250 kVA will be reviewed to determine final control mode and settings.[10]
- Synchronous machine connected DERs shall have the Category A reactive power capability and will be reviewed for the final control mode and settings. Note, synchronous DERs may be required to mitigate high voltage by absorbing reactive power during low load periods.
- Induction-connected DERs do not have a predetermined reactive power requirement. Technical review will determine if supplemental reactive compensation is required.

Based on technical review, the DER facility may be required to operate in one of several reactive power control modes as described in section 6.2. These are normally identified during technical review and confirmed at commissioning. The facility may be asked to operate in a different control mode or setting in the future if PHI determines that it is necessary to regulate voltage in the area.

As specified in IEEE Std 1547™-2018 clauses 5.1 and 5.2 – DER Reactive Power Capability further defines requirements for Category A and Category B generation. All DERs certified to the standard are expected to meet at least Category B requirements.

[10] DERs greater than 250 kVA shall use unity power factor default settings unless otherwise specified by the utility.

6.2. Reactive Power Control

The DER shall be capable to provide voltage regulation by changes of reactive power. PHI will specify reactive power control requirements and settings when needed to actively support voltage regulation. Required modes of voltage regulation using reactive power control include:

- Constant power factor
- Voltage-reactive power Volt/VAR
- Constant reactive power mode

A further description of reactive power control mode requirements for DERs is specified in IEEE Std 1547™-2018 clause 5.3 - Voltage and Reactive Power Control. The standard identifies required voltage and reactive power support requirements. When available, the PHI defined DU-URP default settings in Appendix H shall be used for DERs equal or less than 250 kVA unless otherwise specified in the interconnection application review. Depending on PCC, DERs >250 kVA will be reviewed to determine final control mode and settings.

6.3. Active Power Control

6.3.1. Volt/Watt Control

Volt watt control may be used on a site specific basis. It is recommended that customers install energy storage to reduce the energy curtailment impacts of volt-watt control.

The DER may be required to provide voltage regulation capability by changes of active power. Modes of voltage regulation using active power control include Volt/Watt and Active power-reactive power mode.

Active power control requirements are specified in IEEE Std 1547™-2018 clause 5.4 - Voltage and Active Power Control. The standard identifies required voltage-active power control function requirements and setting requirements for Category B generation. Table 10 in this clause identifies Voltage-active power settings. This setting shall be deactivated unless otherwise specified in the interconnection application review.

6.3.2. Active Power Curtailment and Limited Export Agreements

A DER may request a flexible interconnection (FI) to avoid grid upgrade costs that are incurred because of identified grid impacts during engineering analysis. The FI is implemented through a limited export agreement (LEA) and utilizes the smart inverter’s active power curtailment feature to reduce inverter output when exceeding an agreed ‘export’ stipulated in the LEA. The engineering analysis performed by PHI is as follows,

- Perform feasibility analysis (Load Flow, other technical analysis)
- Identify Impacts to the distribution Grid in the Feasibility Analysis
- Recommend upgrades and downsize options to mitigate to the impacts
- The downsize options are implemented using an LEA where the customer agrees to limit their export to the utility’s downsize KW value recommendation.

The required open loop response time (OLRT) should be determined during the impact analysis performed by PHI engineering. The OLRT should be chosen to prevent thermal overload of any power system equipment.

7. DER Response to Abnormal Conditions

Events on the grid such as an open phase or system fault, and the related actions by the Utility to clear problems or to restore service are not uncommon. This section covers the expected DER response to these conditions. Typically, a different response is expected depending if the event directly affects the DER such as a fault and on the same feeder or if indirectly affecting, such as a low voltage or frequency event from a different part of the grid.

Requirements for the DER response in case of wide area events are coordinated between the Utility and the transmission system operator. PJM is the transmission system operator for PHI.

7.1. Area EPS Faults

DER protective devices shall be rated to safely interrupt fault current levels at the location. Available fault current levels depend on the Point of Connection. The requirement will include the aggregate fault current expected from all sources, the range of fault current scenarios and for all expected feeder operating alternatives.

Requirements for area EPS faults including cease to energize and trip requirements is specified in IEEE Std 1547™-2018 clause 6.2.1 -Area EPS Faults.

7.2. Open-Phase Conditions

Requirements for open-phase include cease to energize and trip within 2 seconds of an open-phase condition and are specified in IEEE Std 1547™-2018 clause 6.2.2. The DER facility must be able to sense open-phase conditions at the reference point of applicability. Note Clause 4.1 (Reference Point of Applicability) in the standard allows for the RPA to be moved to the high-voltage side DER transformers that may otherwise break the zero-sequence continuity.

7.3. Area EPS Reclosing Coordination

Utility automatic reclosing practices for overhead circuits are aimed to maximize the reliability of service to other customers. Interconnecting DERs should not require modifying standard auto-reclose schemes at transmission substations, distribution centers, or other sectionalizing devices. The IC is responsible for protecting the DER facility's equipment so that automatic or manual reclosing, faults, or other common grid disturbances do not cause damage to the equipment.

When automatic reclosing may result in equipment damage or a safety hazard, either to the Utility system or customer facilities, PHI will require additional protective equipment be installed. For example, some DER configurations may require direct transfer trip of connected DERs for line faults. This will usually consist of communication and/or control equipment to disconnect the customer- or third party -owned DER (or to confirm that it is disconnected) before the Utility supply line is reclosed.

IEEE Std 1547™-2018 clause 6.3 - Area EPS Reclosing Coordination identifies requirements for Area EPS reclosing. These include requirements for coordination with the utilities reclosing scheme, consideration when entering service, and voltage ride-through requirements for consecutive temporary voltage disturbances caused by reclosing sequence.

7.4. Voltage Trip and Ride-through Requirements

Manufacturer specifications for all voltage protection schemes must be submitted to PHI for review if other than default settings for ride-through Category II of IEEE Std 1547™-2018 are used. If this protection is not embedded within a tested, certified, and listed interconnection equipment, PHI shall have the right to require testing of the protection system at the customer's expense.

All synchronous machine DERs shall provide Category I capabilities and all inverter-based DERs shall provide Category III (if *P1547-2018*a Amendment is approved) capabilities. Any instances that do not fall within the above capabilities shall be reviewed on a case-by-case basis and with the Area EPS Operator making determination[11] for requiring Category I, II or III.

7.5. Frequency trip and ride-through requirements

Frequency trip settings and ride-through capability requirements for abnormal conditions are specified in IEEE Std 1547™-2018, clause 6.5, and are the same for Category I, II, and III. PHI requires the default settings specified in the standard for both ride-through capability and trip settings.

Manufacturer specifications for any frequency protection schemes must be submitted to PHI for review if any settings are changed or if non-standard settings for ride-through Category II are used. If this protection is not an integral part of a listed, manufactured power source interconnection system, PHI shall have the right to require testing of the protection device systems at the customer's expense.

Rate of Change of Frequency (ROCOF) ride-through requirements, and voltage phase angle changes ride-through requirements shall also apply. All synchronous machine DERs shall be assigned to provide Category I voltage phase angle capabilities and all inverter based DERs shall be assigned to provide Category III voltage phase angle capabilities. Any instances that do not fall within the above assignment shall be reviewed on a case-by-case basis, with the Area EPS Operator making determination for requiring Category I, II or III voltage phase angle capabilities.

For frequency-droop requirements, all synchronous machine DERs shall be assigned to provide Category I capabilities and all inverter-based DERs shall be assigned to provide Category III capabilities. Any instances that do not fall within the above assignment shall be reviewed on a case-by-case basis, with the Area EPS Operator making determination for requiring Category I, II or III frequency-droop capabilities. Frequency-droop default settings shall be used.

For Category II and III, DER frequency droop response is required during low frequency operation and shall be subject to the available active power and any headroom available. Response to high frequency conditions shall be mandatory for all DERs.

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[11] PHI will consider Annex B of IEEE 1547™-2018 when making these determinations on a case-by-case basis.

8. Protection Coordination Requirements

The Utility will determine the bus and line configurations and the protection requirements that are necessary to connect the DER proposed in the IC's application. This section provides protection guidelines and requirements of the most commonly used configurations for parallel operation. Protection requirements for a specific plant may be greater than those listed, based on existing system conditions (e.g., other existing or previously queued DERs on the same circuit), and are considered on a case by case basis.

In the case of DER plants, such as PV with multiple inverters or other certified equipment, additional equipment is often required to provide adequate protection of the T&D system. Requirements for additional protective equipment due to parallel operation of DERs will vary depending on the capacity (MW) of the DER facility and on the configuration of the local Utility system.

Typical protection requirements for all sites are covered in this section. Additional specific protection requirements for radial feeders is provided in Section 10. Requirements for network connected DERs are in Section 11. Examples of relay and relay functional requirements for different types and sizes of DER plants are listed in Appendix D. Finally, general protection schemes are further described in Appendix E that provide basic information on the types of protection schemes necessary for generator Parallel Operation.

8.1. Buffer Zone Capacity

Buffer zones are set around specific DER integration requirements such as current levels, individual or aggregate DER capacity, and reverse power kVA limits. Buffer zones indicate nearing, or exceeding, a limit and provide a margin of safety. They indicate when mitigation alternatives need to be considered for interconnection, for example, at a substation, feeder, or PCC hosting capacity limit.

8.2. Unintended Islanding Detection

Anti-islanding capabilities are required for all DERs and for all installations. The anti-islanding protection shall trip the DER within 2 seconds of the formation of an island (loss of grid power). Trip time for DERs on feeders protected with automatic reclosers will need to be coordinated with the reclosing systems. This may require additional equipment such as transfer trip or suitable alternative.

PHI requires the developer to identify and disclose the method of islanding detection that is being used for all DERs above 250 kW. Detection methods are required for all sizes in cases where the aggregate DER penetration level connected below the next upstream automatic sectionalizing device exceeds 67% of the minimum load on that section (or minimum daytime load in case of solar PV).

PHI reserves the right to require a customer to disconnect the DER from the PHI distribution system at any time when necessary to protect the grid and/or other customers. Additional requirements for anti-islanding protection are specified in IEEE Std 1547™-2018 clause 8.1 - Unintentional Islanding.

8.3. Transfer Trip Protection

Often referred to as Direct Transfer Trip (DTT), this protection is used for most synchronous generators and for larger inverter connected DER installations. It may be required for smaller DER applications when the feeder hosting capacity exceeds buffer zone limits by DER connections. The objective of DTT is to quickly and reliably remove feeder distributed generation when grid power is interrupted and cause system conditions such as ground fault overvoltage. A secondary objective for DTT is to clearly distinguish events caused by bulk system faults without any interruption of power and where the DER should not trip.

In most cases a fiber-optic cable or another acceptable communications medium is required to coordinate feeder or bulk system fault response with the protection scheme of the distribution system. This requirement depends on DER type, unintended island detection and/or DER penetration levels relative to the feeder capacity. Criteria currently being applied where transfer trip is required include:

- Any inverter-based generator is anticipated to exceed the reverse power safety buffer on any PHI equipment serving the plant.[12]
- Any synchronous connected (rotating machine) if the nameplate rating is greater than 1/3 of the net minimum load in each upstream protective zone.
- PHI will consider all existing generation with and without DTT in the same zone of protection in the determination of a DTT requirement.

As an alternative, Transfer Trip will not be required for inverter-based generators connected to ACE/DPL substations with installed or enabled DER overlimit schemes.

8.4. Overcurrent and Reverse Power Flow Protection

The DER shall not generate current flow more than the component rating for Utility equipment. This is inclusive of allowable, emergency, and fault duty system ratings.

Overcurrent and reverse power flow protection and ground fault overcurrent protection is required to be coordinated with upstream protection devices and should be set to be capable of sensing faults on the interconnected feeder.

8.5. Short Circuit Current Interrupting Capacity

When adding DERs, the short circuit current levels (in aggregate from all sources) resulting from the addition of the DER shall not exceed 85% of the interrupting rating of any impacted Utility or customer-owned protective devices and equipment.

The DER (in aggregate from all sources) shall not contribute more than 10% of the distribution system's maximum available fault current at the primary voltage point of common coupling (PCC). If this limit is exceeded additional engineering review may be required.

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[12] Direct Transfer Trip for inverter-based generators can be waived, at the discretion of System Protection & Control, if substation distribution transformer has an acceptable overlimit/3V0 protection scheme implemented or is designed to withstand reverse power transient conditions.

The DER customer may be required to redesign their facility to reduce fault contributions. These redesigns include, but are not limited to:

- Installing a generator with adequately large sub transient reactance
- Installing a transformer with sufficiently high impedance
- Installing a current-limiting reactor

8.6. Protective Relays (or built-in protection functions)

Interconnection configurations are site and feeder dependent. PHI will determine the protection requirements that are necessary to connect the DER. The types of protection required depend on the DER and the site. Appendix B identifies common DER configurations by size, certification, and type of distribution circuit. Typical protective relay functional requirements are in Appendix D.

8.6.1. Review of Specifications

Manufacturer specifications for frequency and voltage protection schemes must be submitted to the Utility for review. If this protection is not an integral part of a listed, manufactured power source interconnection system, PHI shall have the right to require testing of the protection device systems at the customer's expense.

8.7. Telemetry

Telemetry shall be implemented for any DER larger than 2 MW AC as well as for any DER 250 kW AC or greater on a feeder that has or may have distribution automation, with the exception of Pepco-MD and Delmarva-MD.[13] PHI reserves the right to require telemetry as necessary for monitoring and control to maintain reliability. PHI retains the discretion to determine when required for smaller DER interconnections to install such equipment.

PHI will specify all necessary protective relaying, communication, and SCADA requirements for DER interconnection. Interconnection-specific details of telemetry requirements will be provided at the initial project meeting with the Utility. The IC will be responsible for the installation cost and ongoing communication costs of the DER plant required telemetry.

DER plant telemetry normally monitors 3-phase voltages, 3-phase amperages, total MW, total MVAR, MW-Hours[14], and MVAR-Hours[15] and is required under the following circumstances for radial-connected DERs:

- Any system 2 MW or greater.
- Any system with required remote trip shall have continuous telemetry that monitors plant generation output.

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[13] In Maryland, telemetry for systems between 250kW and 2MW will be recommended in order to interconnect under the Level 2 provisions, as 15 percent of the typical line section annual peak loading exceeds 250kVA. Systems that do not consent to the recommendation may be subjected to an additional site-specific feasibility study under subsequent levels to identify an alternative impact mitigation.

[14] MW-Hours requirement may be waived by the utility

[15] MVAR-Hours requirement may be waived by the utility

- If the plant requires transfer trip communication for protection, then transfer trip communication status shall be telemetered.

Note that special telemetry requirements for Network Service can be found in Section 11 and any related interoperability requirements for telemetry are in Section 12. Meanwhile, Appendix G delineates telemetry options for plants ≥2 MW.

For solar or wind DER on a campus, or located adjacent to each other within 2000 feet, the DER are co-located and aggregated telemetry of the DER is required. Other types of generation such as rotating machinery shall require separate telemetry from the solar or wind.

8.8. Remote Trip (via Cellular or Radio) Capability

An Automatic Circuit Recloser (ACR) shall be required, at the customer's expense, for DER systems 1 MW or greater if the system supplies no electric customer load other than the DER station load. This is not an alternative to any DTT protection requirements.

The ACR shall have appropriate relaying and remote-control capability. Depending on location and coordination with other feeder protection, the ACR monitors local voltage and plant current and may be programmed to trip for generator or feeder faults, for sustained voltage outside of predefined limits, and for outages.

NOTE: If the DER is behind the customer's meter, PHI will work with the customer to establish a means of tripping the DER without loss of service to other loads.

8.9. Other Equipment and Protection Requirements

For customer locations where switchgear is equipped with alternate feeds, and employs automatic-transfer capability, protection shall be provided to block the transfer while DERs are paralleled to the system to prevent an out-of-phase condition. In addition, if required protection is not installed on the customer alternate source, the DER will be tripped before the customer is transferred to the alternative source.

If a PHI owned recloser is not installed at a DER site at the point of interconnection, a lockable, taggable, PHI owned disconnect isolation device with a visible break is recommended to be installed at the point of interconnection (in front of the meter) for DER sites equal and larger than 1MW.[16]

8.10. Arc Flash Limitations

DERs shall not cause the arc flash limit to exceed 8 calories / cm^2 at any location on a substation or circuit.

[16] In New Jersey, the level 2 screening criteria rule must be applied from 14:8-5.5.f Level 2 Interconnection Review. The disconnect isolation device shall only be required if the aggregate generation capacity connected to the feeder exceeds 15% of the feeder's peak load.

9. Power Quality

DER operating in parallel with the grid should not degrade power quality to any other customers served by the electric grid. Several power quality standards have traditionally supported maintenance of voltage and power quality in the electric grid. [17] The latest IEEE Std 1547™-2018, Section 7, addresses the power quality requirements specifically for DERs operating in parallel with the grid. Note these are primarily emission limits for DERs in normal operation, and do not necessarily address inadvertent mis-operation or DER failure modes that may impact other customers on the grid.

For solar or wind DER on a campus, or located adjacent to each other within 2000 feet, the DER are considered to operate in tandem for purposes of power quality impacts to the grid.

Referring to the IEEE Std 1547™-2018 limits, PHI's requires DERs to be certified to meet the standard and any other limits within his Technical Interconnection Requirements.

9.1. Limits on DER DC Injection

Direct current, or a DC-offset, from DERs is restricted because low-levels can saturate instrumentation and interconnection transformers causing mis-operation of power outage. Limits during normal operation are specified in IEEE Std 1547™-2018 clause 7.1 - Limitation of DC Injection.

9.2. Limits on DER-caused Voltage Fluctuations

Voltage fluctuation limits depend on both the DER relative size and the strength of the grid (stiffness ratio) at the PCC. The main concerns are DER-caused fluctuations on the medium voltage power system. PHI requirements address a rapid voltage change (RVC) such as caused by switching large real or reactive power components, a repeating power fluctuation causing flicker, and power fluctuations that cause excessive voltage regulator operations. RVC and flicker limit are specified in IEEE Std 1547™-2018 clause 7.2 - Limitation of Voltage Fluctuations Induced by the DER.

Note, effective mitigation of DER-related voltage fluctuations is normally achieved by ensuring that the proposed grid connection point has sufficient capability relative to the DER plant rating. A stiffness ratio (SCR) comparing the grid short circuit power to the DER plant power of 10 [18]times is normally required depending on the voltage fluctuation criteria under review.

9.2.1. Rapid Voltage Change Limits

In normal operation the DER shall not cause RVC changes that exceed ΔV of 3% at medium voltage and 5% if the PCC is at low voltage. Excluded are rare events such as transformer energization during a plant start-up or restoration.

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[17] Power system compatibility standards such as IEEE 519 (on harmonics), IEEE 1453 (on power fluctuations), and IEC 61000 series (on Electromagnetic Compatibility).

[18] Presented By A. Huque "Grid Forming Inverters," 2021, 2022, 2023, EPRI.

Tom Key, "Photovoltaic Plant Output Variability and Grid Voltage," October 2018, EPRI.

9.2.2. Flicker Limits

In normal operation the DER shall not cause repetitive changes of power output leading to voltage fluctuations. To determine compliance an allocation of the grid's flicker capacity at the PCC is provided to the DER. The allocation is Pst ≤ .35, based on a 10-minute evaluation of DER-caused voltage fluctuations. Compliance can be estimated based on stiffness ratio and plant output variability or can be determined by a measurement using a typical power quality monitor.

9.2.3. Compatibility with Voltage Regulation Equipment

The DER shall not cause excessive operation of Utility owned voltage regulators, tap changers, and voltage or VAR-switched capacitors. Rapid changes, where the voltage recovers in less than 10 seconds, are excluded. The following change limits shall apply to minimize excessive voltage regulating equipment operations:

- Voltage Regulators – voltage changes are limited to ½ the bandwidth of any voltage regulator (line or substation) measured at the regulating device.
- Capacitors – voltage changes are limited to ½ the net dead bandwidth of any switched capacitor bank measured at the device.
- VAR Switched Capacitors – reactive power changes not to exceed ½ the bandwidth of any VAR switched capacitor bank measured at the device.

9.3. Limits on Harmonic Distortion from DER

The DER shall not introduce or promote unacceptable distortions in the grid voltage sine wave at the PCC. This limit is applied to DER current total rated distortion ("TRD") and shall not exceed 5% of the fundamental 60 Hz frequency. Additional requirements for voltage and current distortion individual harmonics is specified in IEEE Std 1547™-2018 clause 7.3 - Limitation of Current Distortion.

9.4. Limits on Transient Overvoltage from DER

DERs operating in parallel with the grid shall not, by their design or application, cause transient overvoltage that may exceed Utility or customer equipment tolerances. Events leading to overvoltage include interaction of the DER during ground faults, with grid switching transients, or from disconnection of the DER.

Specific limits are defined in IEEE Std 1547™-2018 clause 7.4 - Limitation of Overvoltage Contribution. If DERs cause objectionable overvoltage, then mitigation is required at the DER owner's expense.

9.5. Maintaining Phase-Voltage Balance

All 3-phase DER installations shall maintain a balanced power output during normal operations. DER interconnections may not create current unbalance that causes any phase voltage in service to other users to violate PHI requirements for 3-phase balance. In most areas the objective is to limit 3-phase unbalance to 3%. This objective is also identified in the informative appendix of ANSI C84.1, 2016, and is defined as follows:

$$\text{Percent voltage unbalance} = 100 \times \frac{(\text{maximum deviation from average V})}{(\text{Average Voltage})}$$

Unbalance is defined in terms of phase current. As an additional requirement, DERs should not cause current unbalance to exceed planning limits for feeders. This planning limit is a 15% difference in phase currents, calculated similarly as voltage unbalance. If the DER causes current unbalance exceeding this limit mitigation or upgrades may be required.

10. Grid Integration for Radial-Connected DER

10.1. General Requirements

Integration requirements for radial-connected DERs address compatibility of the DER plant at the PCC and along the feeder, both above and downstream of the PCC. Requirements depend on the DER, the location, existing condition, and capacities of the feeder. Key concerns are maintaining service voltage within limits for all customers, operating within the ratings of power delivery equipment, managing reverse power, addressing contingencies requiring feeder reconfigurations and protection coordination. In this section, limits to the individual and aggregate DER, as well as criteria for feeder upgrades are addressed.

10.2. Aggregate and Individual DER Feeder Limits

DER feeder capacity limits and/or reserve capacity limits, if applicable to a jurisdiction, will be calculated on a circuit specific basis and will be incorporated into interconnection impact study by the applicable engineering groups.

10.3. Distribution Service Transformer Limits

An existing service transformer may need to be upgraded to resolve voltage or capacity problems. The most common reason is voltage rise due to reverse power. The following criteria shall apply to determine if a DER interconnection application with any existing aggregate DER requires a change in the service transformer:

- If the DER output is greater than the transformer nameplate rating plus 0.5 kW x all residential premises connected to that transformer or greater than 10% of commercial customers peak load tied to the transformer, the transformer shall be replaced.
- If the existing service is open wye-open delta banks and the DER is three-phase. And if single phase DER exceeds 20% of the capacity of the transformer or is expected to create an unbalance in current of more than 20%, the transformer shall be replaced

Additional sizing and design requirements are discussed in mitigation options and upgrade requirements are covered later in this section for radial integration of DERs.

10.4. Substation Power Transformers Limits

10.4.1. Substation LTC Excessive Tap Movement

The aggregate of large DER will be limited to 50% of the substation transformer normal rating. In the case of transformers paralleled on the low side, the limit is 50% of the sum of the transformer normal ratings. This usually ensures that the LTC (load tap changer) does not operate excessively. PHI will have sole discretion to adjust LTC controller bandwidth settings. Note that small systems (less than the large system size for the circuits’ voltage class), may continue to be interconnected when these distribution transformer limits are reached. In cases, where the above 10.4.1 limit(s) have been exceeded, PHI may recommend a new substation transformer and/or upgraded LTCs.

10.4.2. Substation Transformer Thermal Loading

The absolute net reverse power limit is 40% of the transformer normal rating. In the case of transformers paralleled on the low side, the normal ratings and loads for each transformer shall be added together. This ensures that locations with transfer capability can operate safely where one transformer load automatically transfers to the remaining transformer upon outage of one transformer and prevents de-rating of the transformer's normal and emergency limits. PHI will have sole discretion to exceed the limit in 10.4.2 if PHI can achieve reverse power beyond 40% of top nameplate rating without thermally overloading the transformer and/or de-rating (lowering) the normal and emergency rating of the transformer.

Sizing and design requirements are covered in the mitigation options and upgrade requirements section.

Example: 2 transformer substation, each with normal rating of 40 MVA and top nameplate rating of 35MVA. 20 MW of large PV systems are allowed to apply on each transformer. After hitting the 20 MW limit, smaller units may continue to apply. If/when the reverse power reaches 14 MVA (0.4 x 40MVA), the circuits on that transformer will be fully restricted from receiving any more DERs.

10.5. Thermal Operating Limits

An interconnection shall not thermally overload any electrical equipment based on manufacturer ratings and industry practices for determining limits. Thermal limits shall be based on system rating during normal operation. This includes loading capacity of conductors as determined by size, conductor material, and duct configuration. In addition, the design must ensure that circuit losses on the distribution feeder are equal or less that 3% demand loss and 3% annual energy loss.

Curtailment systems with adequate relaying protection and standardized power control systems may be used to mitigate overloads and are an accepted practice to assure that thermal limits are not exceeded. The default PHI open loop response time to be used when setting a power control system to alleviate thermal overloads is 2 seconds. Utility grade relaying with reverse power flow tripping elements should be utilized in a utility owned recloser installed at the PCC and/or customer owned utility grade relaying installed at the PCC that will disconnect the DER from the PHI distribution system if the full nameplate output of the DER will cause a thermal limit to be exceeded or the nameplate size of the DER is 1MW and greater.

- Fast Curves settings shall not be used on reclosers upstream or downstream of a DER with a PCS system larger than 250KW.
- The DER should be disconnected at the PCC in 5 seconds if the measured inadvertent power export at the PCC exceeds 85% of the export limit.
- The DER should be disconnected at the PCC before the measured inadvertent power export at the PCC causes an upstream recloser or breaker to mis operate.

10.6. DER Customers with Multiple Radial Services

For customers that have multiple normal services, the addition of DERs is limited to avoid any condition where more generation or load is connected to any service than it can accommodate. Limiting conditions include:

- Load is at peak and local generation is lost, and
- local generation is at maximum output and load trips off.

In both conditions circuit ratings and voltage must remain within normal limits for loss of either generation or load. The DER system may be connected to:

- A single circuit that may be reconfigured by PHI to provide an alternative service on the loss of the primary service.
- A dual service where either one of the incoming feeders connects to the DER at the DER operator's discretion. When switching from one feeder to the other the DER will need to be disconnected and then reconnected to the new service.
- A dual service where both feeders can supply the DER at one time or either one of the incoming feeders connects to the DER at the DER operator's discretion. Both feeders can be connected either for a short period of time or longer period based on PHI operational requirements.

10.7. Reconfiguration of Radial Circuits

Circuit reconfigurations of a feeder are not recommended to accommodate an interconnection. Circuit reconfiguration may occur for accommodating load and may accommodate interconnection if reconfiguration is beneficial to the Utility system – for example, improving voltage, loading, transfer capability. Determination if circuit reconfiguration should be used to accommodate an interconnection is at the sole discretion of the PHI utility.

For a new high-side breaker position, the construction and/or modification of the existing bus will be required. The new position shall not utilize a planned future transmission line, distribution transformer, mobile unit, or planned capacitor position.

10.7.1. Distribution Automation ("DA") Schemes

Experience has shown that DA schemes can be compromised by large DER systems in concentrated areas. Both fault location and switching can become more difficult.

The DER shall not interfere with Distribution Automation (DA) schemes. Where DERs may interfere with existing DA schemes (e.g. FLISR- fault location, isolation, and service restoration), the following design requirements shall apply:

- DERs applying within Distribution Automation zones shall not interfere with the proper operation of the scheme. The range of load and DER output levels are checked to ensure proper operation under all conditions otherwise mitigation is required at customer expense.
- DERs proposed within existing protection and automation schemes must be integrated and interoperable to maintain existing levels of reliability.
- Systems 250 kW and greater, applying to circuits that have or can have DA schemes, will be required to have telemetry. This will provide monitoring of electrical

parameters and in the future, control capability that can be exercised during reconfiguration.[19]

10.7.2. Load Transfers

Interconnection of large DERs may prompt a study to determine if there are issues for any PHI planned load transfers. These transfers may be to and from circuits with DERs, and shall be analyzed for the following conditions:

- Load, voltage, fault current, and flicker criteria must be acceptable with DERs in-service and off-line.
- Distribution automation and protection schemes must operate correctly under all conditions.
- Additional fault current contribution from the DER shall not exceed 85% of the fault current capability of equipment belonging to the Utility or primary service customers.
- Permanent load transfers with active DERs are only allowed when engineering review of loading, voltage, flicker, fault current criteria, and protection schemes indicates there are no issues.
- Temporary load transfers are permitted for short term or emergency restoration conditions.
- Automatic and manual switching will be evaluated as part of the DER interconnection review approval process. Any issues that create loss of functionality will need to be addressed.

10.8. DER Reverse Power Limits

10.8.1. General

Reverse power flows shall not be allowed through any electric system components not designed to accommodate it. Distribution components that may not be designed to accommodate reverse power flow include;

- Voltage regulators,
- Distribution power transformers,
- Circuit terminals,
- Network protectors and
- Substation metering.

For example, voltage regulators will not operate correctly under reverse power unless they are reversible and set for cogen or DG mode. They should also have source sensing activated to allow them to operate in a reverse mode if the circuit is reconfigured with the substation source on the other side of the voltage regulator. Many power transformers are not protected for

[19] In Maryland, telemetry for systems between 250kW and 2MW will be recommended in order to interconnect under the Level 2 provisions, as 15 percent of the typical line section annual peak loading exceeds 250kVA. Systems that do not consent to the recommendation may be subjected to an additional site-specific feasibility study under subsequent levels to identify an alternative impact mitigation.

reverse power flow when there is a ground fault on the high-side delta connection and causing ground fault overvoltage.

10.8.2. Reverse Power and Safety Buffers

Components not specifically designed to accommodate reverse power flow require operating buffers to ensure that periods of low load coinciding with periods of high DER generation do not result in reverse power. These buffers are needed for unforeseen conditions such as changes in weather, economics, factory schedules, etc. affecting the load profile on a circuit, section, or power transformer.

Operating buffers to prevent reverse power on non-upgraded circuit terminals, voltage regulators, and distribution power transformers shall be as follows:

- Power flow must be monitored and have adequate protection settings when, or if, the reverse power buffer is reached. The safety buffer requires 20% more native (gross) load than generation to prevent reverse power. For solar there must be 20% more minimum daytime (9am-3pm) native load than generation. If a feeder terminal relaying/metering is not adequate, upgrades may be required.
- When the aggregate full output capacity of all downstream DERs equals or exceeds 80% of the minimum phase native (gross) loading, systems 50kW or less can be added to the feeder(s) until reaching the minimum size buffer in the following table.
- If minimum daytime load thresholds are not met on a substation power transformer, then the feeders served by the transformer shall be restricted to small applications (50 kW or less). When observed minimum net load falls below the minimum buffer in the following table, (minimum daytime load for solar DER), the feeder shall be restricted from all future applications. (In either case, if the applicant desires to pay for necessary upgrades, their project may move forward).
- Reverse power restrictions associated with the buffer are not applicable if substation transformer has a DER overlimit scheme installed or enabled. The next limitation for reverse power not to exceed 40% of substation transformer rating as described in Section 10.4

Note for non-solar DERs:

- Minimum load should be used, not daytime minimum load, as non-solar DERs do not necessarily produce peak output during daytime hours. This also includes Energy Storage Systems that can export to the grid at the time of absolute minimum load.

Note for solar DERs:

- Daytime (9am - 3pm) minimum load shall be used. Local daytime minimum load should be considered the lowest annual daytime load going through the lowest loaded phase of the distribution system. When available, that should be used to calculate the 3 phase power which can be used to check for adequate buffer.
- Should daytime minimum load information not be available, the minimum all-time load of the circuit shall be used for establishing the operating buffer.
- If neither the daytime minimum load information nor circuit minimum all-time load information is available, a reasonable method of estimating the minimum load shall be used, ie 12-30% of peak depending on the load composition of the circuit.

10.8.3. Reverse Power Safety Buffer Requirements

In addition to the requirements discussed above, minimum size of the operating buffer for equipment at its rated voltage shall be in accordance with the following table.

For transformers with installed or enabled DER Overlimit Scheme, the reverse power buffers and associated restrictions will be omitted.

Table 5 – Minimum size of buffer zone for equipment by circuit voltage level

Circuit Voltage Level	Minimum Size of Buffer Zone (Total 3 Phase Power)		
	Voltage Regulators	Distribution Power Transformers[1]	Circuit Terminals[2]
4 kV	100 kW	200 kW	150 kW
12 – 13.8 kV	200 kW	500 kW	250 kW
23 – 25 kV	200 kW	500 kW	250 kW
33.26 – 34.5 kV	300 kW	1 MW	500 kW

[1] Limit does not apply to substation transformers with grounded high-side winding
[2] Upgrade is at the discretion of PHI. Terminals rarely need to be upgraded.

Specific limits and options may also depend on the application and will be addressed in interconnection technical review. Typical application issues related to reverse power include:

- Uni-directional voltage regulators without DG or Cogen Mode or auto-source sensing,
- Transmission-level reverse power limitations,
- Need for 3V0 protection at sub, or power limits, and
- Transformer life/rating concerns.

10.9. Feeder Upgrade Options and Requirements

10.9.1. Service Transformer/Secondary Conductor Upgrades

The following analysis and design requirements shall apply where an interconnection LT 50 kW requires an upgrade to the service transformer and/or secondary conductors. A voltage rise analysis should be performed for any project to determine if the transformer, secondary conductors, or service wire should be upgraded. If available, AMI voltage data will be used to support the voltage rise analysis. If an upgrade is required, the least-cost upgrade correcting the issues should be selected.

For larger primary connected, 3 phase systems, the following transformer requirement may apply:

- Any DER GE 250 kVA may require load taps (+/- 2.5 and 5% typically).
- For DERs in areas where a voltage level is being retired, the developer will be required to provide a dual voltage transformer and associated equipment rated to operate at the higher voltage level, so that if/when a conversion takes place, the transformer will support the new voltage level.

10.9.2. Sub-Station Power Transformers

The following criteria shall apply where a DER plant interconnection requires a substation power transformer upgrade:

- The upgraded or new transformer shall be the standard size and standard design of the Utility for the voltage class.
- Circuits with significant DERs should not use line-drop compensation as a Load Tap Changer ("LTC") setting. Line-load drop compensation is not to be used on any new feeder.
- The LTC shall be a modern vacuum type
- The transformer shall be protected against a high side line-to-ground fault if generation can feed back through the transformer.

10.9.3. Feeder Voltage Regulators

Where a DER interconnection requires a voltage regulator to be added or upgraded, this must be completed before approval to operate. PHI will apply the following requirements if reverse power is possible:

- Upgrades will provide for bi-directional operation.
- Upgrades will include a Cogen or DG operating mode and auto source sensing functionality activated to allow proper regulation in case of reverse power and during circuit reconfiguration such as a DA scheme operation
- Added or modified voltage regulators may require coordination with other PHI regulating equipment. If communication is required, voltage regulators shall be equipped with telemetry to the Operations Center giving operators the ability to change settings and control modes as necessary and for future ADMS volt/VAR control. Interoperability requirements described in section 12 apply.

10.9.4. Capacitor Banks

The following requirements shall apply where a DER interconnection requires a capacitor bank upgrade or a relocation on the circuit:

- Fixed capacitor banks may be upgraded to switched type, removed and/or installed at a new location, as appropriate.
- PHI will determine settings for switched capacitor banks in coordination with any DER reactive power response settings, during interconnection technical review.

10.9.5. Express Circuits

The aggregate limit of DERs interconnecting to an Express Circuit is determined by capacity planning, system protection and business/interconnection engineering, varies by service area and is at the sole discretion of the PHI utility. Express circuits may be connected to more than one customer at the discretion of PHI. The following table indicates maximum limits based on available three phase fault current at the end of the circuit.

Table 6 – Maximum DER limits based on rated circuit voltage

Circuit Voltage	Maximum DER Limit[20]
4 kV	5 MVA
12 – 13.8 kV	15.5 MVA
23 – 25 kV	30 MVA
33.26 – 34.5 kV	45 MVA

Express circuit limits shall be established based upon the following analysis and accepted distribution planning, system protection practices and shall not exceed the maximum DER limit:

- Load flow results, fault analysis, local planning criteria, testing available conductor sizes for voltage rise/drop, fluctuation, and losses.
- Conductor size should ensure that power delivery energy losses (both the demand and annual generation losses) remain less than 3%, proper voltage regulation (ANSI limits, IEEE-1547 voltage change requirements) and thermal rating of the conductor.
- The DER limit should not exceed the maximum DER limit or the relay load limit for the express feeder (see footnote 22).

The following requirements apply where a DER interconnection application requires an express circuit:

- In general, IC shall pay for a new breaker position that will be created at the substation to not utilize ones that are planned to be used for a future new load circuit.
- An express circuit shall not utilize a planned future circuit position or circuit path that could be used to address future PHI load growth.
- Before an express circuit is used for any other purpose than serving the DER, a complete engineering study will need to be performed. The capacity needed for the DER shall not be degraded.
- Conductor size and length of the express circuit shall be selected such that demand, and energy losses are both less than 3%. The loss criteria may be exceeded if the interconnection customer agrees to pay for energy losses above 3%.
- The recommended circuit length is limited to 5 miles for 12/13 kV, 7 miles for 25 kV, and 10 miles for 34 kV.

  NOTE: For ACE and Pepco, no 34 kV Express Circuits will be built as that voltage level is being retired. No 4 kV Express Circuits will be built in any PHI jurisdiction.

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[20] Maximum limit was calculated assuming an end of circuit three phase available fault current equal to 2700 amperes. The circuit specific relay load limit (amperes) must be calculated for a given circuit conductor and length using the following formula: 0.2833 x three phase available fault current at the end of the express feeder. The amount of DER on an express feeder should never exceed the maximum DER limits.

10.10. Circuit & Bus Reconfigurations

Circuit reconfigurations are not allowed to accommodate an interconnection. From time to time, the Utility may perform phase balancing.

For a new high-side breaker position, the construction and/or modification of the existing bus will be required. The new position shall not utilize a planned future transmission line, distribution transformer, mobile unit, or capacitor position.

11. Grid Integration for Network-connected DER

11.1. General Requirements

Renewable generation or other DER facilities can be connected to secondary networks, both area (or grid) and spot, provided they meet the requirements in the following subsections. Some of these limits are based on state rules. Limits also consider Utility industry practices to maintain protection and reliability and the requirements in IEEE Std 1547™-2018 clause 9 - DER on distribution secondary grid/area/street (grid) networks and spot networks Distribution. When any of these application requirements are in question PHI offers further engineering review.

Network connections are generally more challenging than radial because reverse power can result in disconnection from the grid. Prevention of reverse power in network protectors is essential to avoid the cascading loss of the grid connections serving network load. IEEE Std 1547™-2018 clause 9.1 addresses several specific issues related to DER integration into networks.

Note: Application of export limiting relays or a controller at the customer facility can be an effective way to allow interconnections otherwise limited because of back feed risk and unwanted network protector operations. Determination of export or import is normally at the customer metering point and would include the net of customer load and generation. Power control systems are not permitted as a sole solution to limit export on network system but are permitted to supplement reverse power flow relaying.

11.2. Area Networks

Area networks, such as in downtown locations, are typically 120/208V and are served by multiple transformer banks and meshed on secondaries. In area networks DERs must be limited to avoid reverse power that causes network protectors to open. In addition, the DER must not cause network protector cycling. Relative DER size and telemetry requirements to accomplish this are:

- DER systems less than or equal to 50 kW can be approved if the DER maximum generation is ≤5% of the area network peak load. Monitoring and control will not be required. PHI has the right to revise the maximum export level in case of changed conditions or future negative impacts.
- DER systems larger than 50 kW will be required to provide local monitoring of net power (import or export) and control of generation through control relays, or a combination of inverter and dedicated controller. Net power limits will be set to prevent reverse power on any area network protector.[21] In some cases a minimum net import (into the facility) may be required.
- Telemetry will be required for systems larger than 150 kW to collect and provide PHI the monitored data. Interoperability requirements described in section 12 apply. For systems larger than 50 kW and up to and including 150 kW, telemetry and related

[21] The setting is determined based on a 20% safety buffer below the import that would cause network protector operation or cycling. This margin is 20% of the maximum excess generation, or 15 kW, whichever is larger.

interoperability may be required where the system, during daytime hours, operates within 30% of the point where a network protector would inadvertently operate.
- In Atlantic City Electric service territory aggregate PV generation connected to an area network shall not exceed 10% of minimum annual load or 500 kW, whichever is less. The minimum load is calculated based on minimum load occurring during an off-peak daylight period for PV or any off-peak minimum for other generation types. Depending on size, all PHI monitoring and telemetry requirements apply in Atlantic City.

Any mitigations to allow additional DER capacity on an area network will be at the expense of the IC. Typical mitigations are reverse power relays (or a combination of inverter and dedicated controller) to monitor and control the net flow across the customer connection into the area network and to adjust the output of aggregate DER as needed to prevent any inadvertent operation of network protectors.

Customers can export excess generation (up to an allowed Maximum Export Limit) to the network if export can be accomplished without causing reverse power to any of the network protectors at any time. If the buffer for export is too small, customers can be required to maintain a minimum import limit.

The DER system/facility being studied must be evaluated with all other active and pending applications for generation to be added to the network. PHI will have the right to revise the maximum export level (or the minimum import level) in case of future negative impact.

Additional requirements for area networks are specified in IEEE Std 1547™-2018 clause 9.2 - Distribution Secondary Grid Networks. This requires the DER to detect and not maintain an island condition. It also requires that the DER not cause network protectors to operate during adjacent feeder faults and that the DER operation be coordinated with the network protection relays.

11.3. Spot Networks

Spot networks typically deliver 265/460V on the secondary and are fed by two or more sources. Spot networks DERs must be limited to avoid reverse power that causes network protectors to open. In addition, the DER must not cause network protector cycling. Relative DER size and telemetry requirements to accomplish this are:

- If aggregate DER generation is ≤5% of the spot network peak load, monitoring and control of generation is not required. However, export of generation into the spot network transformer(s) for any duration will not be allowed. PHI has the right to revise operating limits in case of changed conditions or future negative impacts.
- If the aggregate DER generation is larger than 150 kW, telemetry is required to collect and provide PHI the monitored data for archiving in the PHI database. Interoperability requirements described in Section 12 apply. For systems 50 kW-150 kW, telemetry and related interoperability, may be required if, during the daytime hours, the system operates within 30% of the point where a network protector would operate to prevent inadvertent operations.
- The facility must maintain a minimum power import of at least 20% of the facility minimum daytime load, or 20 kW, whichever is more. PHI will have the right to revise the allowed injection level in case of future negative impact.

Any mitigations to allow additional DERs on-spot networks are at the expense of the IC. Typical mitigations are reverse power relays (or a combination of inverter and dedicated controller) to monitor and control the net flow on the customer connection to the grid and to adjust the output of the aggregate DER as needed to prevent any inadvertent operation of network protectors.

Note that IEEE Std 1547™-2018 clause 9.3, Distribution Secondary Spot Networks, requires that DER not enter service until greater than 50% the network protectors are closed.

11.4. Customer-owned Export Limiting Relays

Specific requirement for application and review of customer-owned export limiting systems are as follows:

- Customer shall install controls and relay(s) that monitor the entire load of the spot network on all three phases. The control shall be set up to maintain the minimum kW buffer. If import exceeds the limit, the control system shall curtail or trip the generation. Response time for curtailment or trip should occur instantaneously.

Relays installed at the customer site must trip before any PHI system network protector. A direct trip without time delay is required using a function 32 – directional Power Element and a function 67 – directional current element. If DER output reduction is possible, it must complete curtailment before reaching the protection trip point and will maintain the reverse power trip option as a backup. The relay shall provide metering and status values to PHI equipment via DNP 3.0. A DNP map for the required status/analog points shall be provided. The relaying plan and settings must be submitted to PHI for review and approval.

11.4.1. Special Review and Evaluation of Network Protection

Witness testing includes a PHI System Protection / Telecom point-to-point testing of any protection scheme. Following review and approval of the relay one-line, a date for point-to-point testing will be agreed upon during normal working hours, approximately 1-2 week(s) prior to site energization. Customer personnel should be available to assist in injecting current to the relays to send the required metering and status values for confirmation at the PHI control center.

In addition, the ability to reduce output of inverters or trip the inverter system based on relay feedback must be demonstrated. At a mutually agreed upon test date, PHI will work with the contractor to perform the following tests of the required monitoring and control system. Note that these tests (listed in no order) can be modified and additional tests can be added.

- Test the trip point (when the set point is reached)
- Test shunt trip (backup relay) – if applicable
- Obtain Relay settings as it is setup for the relay to trip generation

For Solar PV plants, if the test day is overcast without ability to show a substantial PV output, customer must simulate load and generation conditions to feed into the relay and create a trip condition.

11.5. Special Control Requirements for Network Service

Telemetry is required for all DERs larger than 150 kW and for some 50 kW to 150 kW installed with network service. Requirements are:

- To monitor three-phase voltage, three-phase power, three-phase current, total MW, total MVAR, the power crossing at the interchange of the facility, and any solar output. Remote trip capability may also be required. The monitored values shall be brought back into an Energy Management System (EMS), DMS, DERMS, or other management system and stored into a PHI database. Interoperability requirements described in section 12 apply.
- A telemetry cabinet to host telecommunication equipment shall be supplied by PHI for installation at the site by the customer. The cabinet shall be installed no more than 50-feet from the customer RTU. The customer shall provide an RS-232 serial cable for connection and 120VAC power source shall be provided nearby.
- The customer is responsible to install a radio antenna coax cable at the location specified by the PHI telecommunication team and should there be a need to pull cable to the antenna location, a minimum of a 1 ¾ inch conduit path shall be provided by the customer. Conduit bend minimum radius shall be 1 foot and 90 degree bends shall be avoided.
- The customer is responsible to configure and provide at least one RTU with RS-232 cable connection which will require a DNP 3.0 communication protocol.

12. Plant Interoperability

12.1. General Requirements

Requirements for interoperability of the DER is specified in IEEE Std 1547™-2018 clause 10 Interoperability, Information Exchange, Information Models, and Protocols. DERs are expected to follow these requirements. This chapter defines additional and/or more specific requirements for PHI and clarifies which systems must be connected to telecommunications networks for data to be collected and/or exchanged. For Customer owned generators seeking parallel operation through an Interconnection Request directly to PJM, the generator(s) must adhere to the monitoring, control and remote telecommunication requirements as outlined in PJM Manual 01, *Control Center and Data Exchange Requirements* and PJM Manual 14D, *Generator Operational Requirements.* Additional PHI monitoring, control and telecommunication requirements are detailed below and also apply to PJM queue projects, except as noted, or if further defined in an Interconnection Agreement.

12.2. Interoperability for DER Plants

Interoperable telemetry shall be available in all DERs following IEEE Std 1547™-2018 clause 10. These requirements include more extensive monitoring, control, and information exchange requirements covering many parameters including nameplate information, configuration information, monitoring information, and management information. PHI reserves the right to use the full information that is identified in these requirements. This interface will be utilized (telemetry connected to a communication network) as specified in other areas of this document.

12.2.1. Capability Requirements

Interoperability capabilities include specific protocol and communication performance requirements.

IEEE Std 1547™-2018 specifies standardized communications interface for all DERs that shall be locally available at the DER location. Communications should not depend on vendor specific protocol or remote communication. Any setting changes must be reviewed/approved or initiated by the Utility.

A standardized, local DER communication interface makes it possible for PHI (or other parties) to perform monitoring and management/control of DERs by deploying an appropriate network. It further allows utilities to collect standardized configuration information, such as nameplate ratings.

12.2.2. Communication Protocol Requirements

Interoperability requirements include specific protocol requirements and communication performance requirements. IEEE Std. 1547™-2018 specifies three applicable protocols: IEEE 2030.5 (SEP2), IEEE 1815 (DNP3), or SunSpec Modbus. PHI requires DERs to speak the following protocols, depending on the DER's size:

	IEEE 2030.5 (SEP2)	IEEE 1815 (DNP3)	SunSpec Modbus
LE 250 kW	Allowed	Allowed (see notes)	Required
GT 250 kW	Allowed	Required	Allowed

Note: Required protocols must be present. Other interfaces including IEEE 2030.5, IEEE 1815, SunSpec Modbus, or others are allowed if the required interfaced is present.

Additional notes and considerations:

- IEEE 2030.5 is suitable for use in integration communication networks and includes cyber security definitions.
- SunSpec Modbus for small-scale DERs is a simple protocol that is well suited for local interfaces which reduces integration complexity, increasing interoperability.
- IEEE 1815 (DNP3) for large scale DERs is compatible with Utility SCADA systems and well suited for cohesive integration with DA and DMS for overall distribution optimization.
- When the Utility requires telemetry on systems less than 250kW, output should be DNP3.

12.2.3. Unlock Mechanism Requirement

Some DERs have historically included methods to lockout communication through the local interface, usually with passcode access required. Some vendors may continue this practice even after open standards are required. This proprietary step to unlock the device is only allowed for the initial set up and for certification. The open standard protocols do not support this and cannot unlock a DER that has been locked using proprietary means.

For all inverters certified to IEEE 1547-2018, PHI requires the unlock mechanism be implemented such that:

1. The Utility is not locked out of the communication interface. This is the simplest way to ensure future access. It leaves local communication ports open, like local keypad interfaces.
2. Allow devices to be locked but PHI specifies the messages and passcode(s) by which they are unlocked or locked so that there is a known, common way to gain access to all DERs in the service territory.

PHI prefers the local DER communication interface not to be locked out (option 1) unless another method is mutually agreed upon. If option 2 is chosen, PHI requires the IC to provide confirming documentation to the Utility that describes the messages and passcode(s). for each DER.

12.3. DER Communication Interface

12.3.1. DER Plant Requirements

The plant shall provide all telemetry, control, and associated equipment that is required to meet the telemetry requirements highlighted throughout this document. This equipment includes DER interoperability requirements as well as interoperability with the plant controller. This equipment shall meet PHI specifications. If the communication link used for generator remote trip or telemetry fails, PHI will allow the generation to stay on-line for up to 72 hours. If the problem is not corrected after 72 hours, PHI will require that the unit come off-line until the problem is resolved. PHI will make every effort to respond to the failure of the communication link in a timely manner or as system conditions dictate. PHI field personnel will only troubleshoot up to the point of ownership, the Generation Owner is responsible for failure analysis and corrections on their own equipment. In situations where system conditions warrant, PHI may allow the developer to operate beyond 72 hours without the communication link, but such action will be at the sole discretion of PHI's System Operations. Conversely, if the loss of telemetry poses an immediate reliability or safety concern, PHI reserves the right to remove the unit from service prior to the 72 hours.

12.3.2. PHI Protocol

PHI will provide and install, at customer cost, telemetry, control systems and protection systems required for interoperability of the DER and plant controller with the Utility communications and control systems. These systems may include such items as communication systems for monitoring DER information, controlling DERs, tripping DER units, and tripping breakers/reclosers.

12.4. Monitoring, Control, and Information Exchange

12.4.1. Inverter-connected Generation Requirements – PJM Market or DER GE 1 MW

Any inverter-based generation project that is participating in the PJM wholesale market or is 1 MW or larger shall be required to install communications to ensure real-time SCADA telemetry.

Any project 1 MW to 5 MW requires:

- Installation of a recloser or acceptable approved device. NOTE: If the DER is behind the customer's meter, PHI will work with the customer to establish a means of tripping the DER without loss of service to other loads.
- All SCADA points listed below – except relay failure status
- Polling Rate of 5-minute intervals or shorter as required by the Utility.

Any project that is greater than 5 MW requires:

- Installation of communication equipment to support required polling rate
- All SCADA points listed below
- Polling rates of 30 seconds (analog) and 2-4 seconds (status)

Any project that is participating in the PJM Wholesale Market requires:

- Installation of communication equipment to support required polling rate
- All SCADA points listed below
- Polling Rates of 10 seconds (analog) and 2-4 seconds (status)

The purpose for real-time SCADA requirements is monitoring the impact of larger installations on Utility system, monitoring performance during transmission and distribution faults, monitoring feeder loading and performance (voltage and frequency) and verifying islanding performance. Inverter communication specifications to be determined based on approved tariff requirements.

The Utility reserves the right to require smart inverter interface where needed with the ability to control volt/VAR settings, ramping, delay times, curtailment, etc. if required to maintain system reliability such as in temporary circuit reconfiguration or abnormal system events.

The following is a preliminary list of SCADA points required. This represents the minimum list of data points required.

- 3 Phase kV (Voltage)
- 3 Phase Amps
- 3 Phase MVA
- 3 Phase MW
- 3 Phase MVAR
- 3 Phase MWh
- Relay Failure Status
- Breaker Status (connected/disconnected)
- Frequency

12.4.2. Machine-connected Generation Requirements

Some generators will require continuous telemetry to the Utility's operation facilities. These will typically be large generators, generators involved in wholesale transactions, or generators which are dispatchable by the Utility, depending on state requirements for metering on DERs such as PV.

Generators that meet the following criteria require implementing telemetry to Utility's control center and telephone communication to the revenue meter. Required telemetry is listed below each criterion. If more than one criterion applies to a generator, the telemetry requirements of each criterion must be met. If PJM's metering requirements are stricter than Utility's, than PJM's metering requirements take precedence.

If the aggregate generation at a site is greater than 10 MW.

- Continuous telemetry is required.
- Instantaneous MW and MVAR of each generator.
- Instantaneous revenue grade MW and MVAR; and cumulative revenue grade MWh and MVARh at all points of interconnection with the Utility.
- Status of all circuit breaker(s) which can disconnect a generator from the Utility System.
- Status of bus tie circuit breaker(s).
- At least one bus kV measurement.

If the generation is involved in sales transactions through the Utility System.

- Continuous telemetry required.
- Instantaneous revenue grade MW and MVAR; and cumulative revenue grade MWh and MVARh at all points of service from Utility.
- Aggregate instantaneous MW and cumulative MWh of all third-party loads inside Utility's control area.

If the generation is involved in a Power Purchase Agreement (PPA) or participating in the PJM capacity markets which contains unit specific performance or a unit specific payment structure.

- Continuous telemetry required.
- Instantaneous revenue grade MW and MVAR; and cumulative revenue grade MWh and MVARh at the generator's step-up transformer high side (or equivalent net output) for each unit.
- Instantaneous revenue grade MW and MVAR; and cumulative revenue grade MWh and MVARh at all points of interconnection with Utility all points of service from Utility.

If the generation will be remotely turned on/off by Utility.

- Continuous telemetry required.
- Instantaneous revenue grade MW and MVAR; and cumulative revenue grade MWh and MVARh at all points of service from Utility.
- Supervisory control for generator (or generators').

If multiple generators over a large area with an aggregate generation greater than 40 MW are being centrally controlled.

- Continuous telemetry required.
- Aggregate instantaneous MW of all generators.

If the generation, for protection, requires transfer trip communication, then generation site transfer trip communication status shall be telemetered.

Generators that do not participate as capacity resources must provide instantaneous real power data only if they are:

- 10 MW or larger
- Greater than 1 MW and connected at a bus operating at 34 kV and above

For additional requirements, refer to PJM Manuals M-01 and M-14D for further data requirements.

Manufacturer specifications for frequency and voltage protection schemes must be submitted to Utility for review. If this protection is not an integral part of a listed, manufactured power source interconnection system, Utility shall have the right to require testing of the protection device systems at the IC's expense.

13. Plant Revenue Metering

For purposes of this document, revenue metering shall refer to the meter or meters used for billing purposes and the associated current transformers and potential transformers (collectively known as “instrument transformers”), communications equipment, and wiring between these devices. The basic configuration consists of directional revenue grade metering (import and export) at each point of interconnection with the Utility system. Additional separate revenue metering for the gross output of the generation and for auxiliary retail loads may be required, depending on the generation capacity, telemetry requirements, applicable contractual provisions, and associated tariffs.

All revenue metering equipment must comply with the state public service commission applicable specification sections covering revenue metering, as well as, technical requirements for the location provided by PHI. In addition, generation and auxiliary metering in most jurisdictions must have the ability to connect to an Advanced Metering Infrastructure (AMI) system.

For Customer owned generators seeking parallel operation through an Interconnection Request directly to PJM, the generator(s) must adhere to the metering requirements as outlined in PJM Manual 01, *Control Center and Data Exchange Requirements, Section 5: Metering Requirements* and PJM Tariff, Attachment O, Appendix 2, section 8. *Additional PHI metering requirements are detailed below and further defined in an Interconnection Agreement, and also apply to PJM queue projects, except as noted.*

- *The requirements for each parallel generator installation will be reviewed and revised on a case-by-case basis. Listed below are the standard requirements for generator Interval Metering. The Company, however, reserves the right to specify the required interval metering equipment for each paralleled generator site.*
- *All paralleled generator Facilities shall be metered in accordance with applicable tariffs and specifications provided in approved Company publications. (Note: Does not apply to PJM generation queue projects.)*
- *An Interval (Revenue) Meter must be located at each Point of Common Coupling. The Interval Meter will record input and output for both MW-Hour and MVAR-Hour.*
- *The Generator Owner may net retail site load behind a single meter at the Point of Common Coupling except:*
    - *A separate Interval Meter is required for each generator if the generator or aggregate generation is greater than 2 MW, unless otherwise specified in an Interconnection Agreement.*
    - *In cases where the generation is served under a generator “Standby Tariff”. Under this tariff, each generator must have a separate Interval Meter to record input and output for both MW-Hour and MVAR-Hour. (Note: Does not apply to PJM queue projects.)*
- *Generator site auxiliary loads that are not measured by the generator Interval Meter will require a separate meter.*

- *The Generator Owner shall supply a telephone line for the Interval Meter data recorder which allows the Company to dial up and retrieve the Interval Meter data remotely. Specific requirements will be determined on a case-by-case basis.*
- *Unless otherwise mutually agreed upon by the Company and Generator Owner, the Company shall install and own all Interval Metering equipment at the Point of Common Coupling and on the generator(s). The Generator Owner shall pay the Company the initial costs to procure, install, test and startup the metering and associated related equipment. Thereafter, the metering equipment shall be owned, operated and maintained by the Company. Costs for any maintenance, testing, and/or repairs will be at the Generator Owner's expense. (These provisions are subject to possible modification by PJM, regulatory commissions or applicable tariffs. PJM allows Generator Owners to install, own, operate and maintain the Interval Metering (i.e. PJM "Metering Equipment")) The Company and the Generator Owner may agree to have the Generator Owner install the metering VTs (voltage transformers) and CTs (current transformers) within the Generator Owner's switchgear equipment.*
- *All metering shall comply with ANSI and Company technical requirements (including meter model, options & programming). The Point of Common Coupling and generator Interval Meters shall be bi-directional so that power flow (including reactive) to and from the Generator Owner's site can be separately recorded. The Point of Common Coupling Interval Meter shall be equipped with detents to prevent reverse registration.*
- *The Generator Owner may, at its sole option and cost, install or have the Company install additional metering equipment to meet any special needs that the Generator Owner may have.*

14. Commissioning and Verification Requirements

14.1. General Requirements

This section covers several steps to verification that the interconnection meets requirements and can be commissioned. It covers a commissioning process including configuration of DER functional setting, evaluation of documentation, determination of tests required to be completed before witness testing. References to determine test requirements that depend on the plant size and type, as well as, any specific protective relay test requirements are provided. This section also covers recommissioning and periodic testing.

Specific requirements for each project will be communicated to the customer/developer. These requirements will be a subset of the items found in this section.

14.2. DER Commissioning Process

The DER facility commissioning process shall be planned and carried out by the customer after construction is completed and the site is ready to be energized. At a minimum, the scope of the commissioning process to be performed shall include commissioning tests specified by IEEE Std 1547™-2018, clause 11.2.4.3 - DER as-built installation evaluation, clause 11.2.5 - Commissioning tests and verifications, and clause 11.3 - Full and partial conformance testing and verification. The commissioning process shall verify that the facility does not create adverse system impacts to the electric grid and to other customers served by the grid.

14.3. Operating Requirements and Supplemental Form Documentation

Prior to commissioning tests, the DER facility owner or installer shall acknowledge adherence to the proposed operating requirements and/or DER settings by executing operating requirements documentation or other supplemental forms provided within the interconnection agreement and its attachments with the Utility. For facilities that do not require commissioning tests, the aforementioned documents will be a prerequisite to receiving final permission to operate. Further validations may be necessary on a case basis.

14.4. Configuration of Functional Settings

Prior to commissioning tests, the IC shall configure the DER facility's functional settings by means of one of the following options:

- Option A: Selection of a manufacturer-automated profile (MAP)
- Option B: Use of a configuration and validation toolkit that uses the *local DER communication interface*
- Option C: Integration with the Utility's DER settings requirements or if applicable, the Utility's DER management system (DERMS)

14.5. Evaluation of Documentation

Prior to the performance of commissioning tests by qualified personnel, PHI will evaluate the on-site documentation to confirm that it is consistent with the application and other required project documentation. This DER evaluation will determine whether commissioning can proceed and the level of commissioning that is required. Certain commissioning tests need to be completed by the IC before Witness Testing can take place.

Identification of the commissioning tests to be performed will be dependent on the results of the documentation evaluation prior to commissioning and whether the RPA is at the PCC or PoC as defined by IEEE Std. 1547-2018™. Commissioning tests for DERs with RPA at the PCC shall be performed per IEEE Std. 1547-2018™ "Table 43 – Interconnection test specifications and requirements for DERs that shall meet requirements at the PCC" and as per guidelines, in the latest IEEE Std. 1547.1. Commissioning tests for DERs with RPA at the PoC shall be performed per IEEE Std. 1547-2018™ "Table 44 – Interconnection test specifications and requirements for DER that shall meet requirements at the PoC" and as per guidelines in the latest IEEE Std. 1547.1.

14.5.1. Review to Confirm As-Builts

The following installed equipment information is required before witness testing for confirmation of consistency with previously provided documentation:

Equipment	Information Required
Inverter	- Ratings: Mfg., Model, Rated kW, V on the application will be compared to equipment installed in the field. - Inverter Firmware Version - Inverter Settings
Interconnection transformer[1]	Load side winding connection, High side winding connection, Primary Voltage, Secondary voltage, Rating, and % impedance if customer owned. If owned by the Utility, a contractor supplied picture of the transformer with its size and ID number clearly visible will be used to verify information in GIS. This can speed up secondary voltage rise analysis and service transformer adequacy where data may not be complete in GIS.
Primary fuse / recloser[1]	Rating / Settings
Primary PTs for Ground Fault Protection[1]	PHI primary PT's shall be wired to customer load side relay to provide Device 59G or Device 27/59 protection for Area EPS Faults

[1] Information not required for interconnections ≤ 25 kW.

14.6. Commissioning Tests

14.6.1. Protective Relay Tests

Qualified testing personnel must perform tests on the IC's protective relaying prior to energizing from the PHI system. Testing requirements will be evaluated and determined on a case-by-case basis by the Utility, dependent upon the configuration of the proposed generating facility. Portions of the IC's equipment may be energized when the associated testing for that portion has been completed and verified. The following table is provided to serve as guidance and may or may not be prescribed in the IC's relay equipment inspection requirements.

Table 7 – Testing requirement for relay equipment

Relay Equipment Testing Requirement	Type of Testing
Protection Device Function	Variable – Determined by Relay Type
Acceptance Testing	Test Document Review
Setting Calibration	Witness / Functionality
Tripping Check	Witness / Functionality
Sensing Devices	Test Document Review
Primary Current / Voltage	Witness / Functionality
Telemetry for Protection Scheme	Witness / Functionality

The configuration of settings for the protection systems shall be the settings previously provided by the IC to PHI and approved by PHI. These settings shall not be altered during commissioning without the authorization of PHI.

Additional requirements for tests and verification of the DER system is specified in IEEE Std 1547™-2018 clause 11 - Test and Verification Requirements. These include different commissioning requirements based on whether the RPA is at the PoC or PCC and whether the type testing performed was on the DER Unit, DER System or Composite system and the results of the DER evaluation performed before commissioning.

14.6.2. Plant Commissioning Tests

Commissioning requirements are dependent on the size of the DER, DER certification, and whether the RPA is PCC or PoC as identified in IEEE Std 1547™-2018. The following criteria will be considered to identify the commissioning test requirements of the IC.

- Certification of DER for RPA at PoC or DER System for RPA at PCC. Classifications include DER Unit (PoC), DER Composite for PoC compliance, DER System (PCC), or DER Composite for PCC Compliance.
- Results of DER evaluation by PHI.

Commissioning tests shall be performed according to the appropriate requirements of IEEE Std 1547™-2018 clause 11 and in accordance with IEEE Std. 1547.1™ (expected publication 2020). Commissioning tests shall be performed by qualified personnel. For DER systems with plant controllers, commissioning tests shall include the plant controller. The results of the commissioning tests will be evaluated by PHI before Witness Testing can take place.

In addition to the commissioning test requirements identified in IEEE Std 1547™-2018 smarter inverter settings shall be verified, and protective relaying shall be tested as identified in Section 14.3 Commissioning Protective Relaying for Feeder Protection and Communications of this document. Commissioning is also required for telemetry systems depending on DER size and application. Note additional commissioning and witness testing requirements for Secondary Network can be found in Section 11.1.2 – Special Review and Witness Testing for Networks.

A commissioning checklist can be found in Appendix F. The commissioning checklist identifies general commissioning requirements. These requirements are based on common DER configurations and levels as identified in Appendix B. These configuration levels are based on several parameters including:

- Plant DER kW - In general, the larger the plant DER kW, the more extensive the commissioning requirements. Different requirements are shown in the checklist in Appendix D for DER 25 kW or less, greater than 25 kW to 250 kW, greater than 250 kW to 2 MW, greater than 2 MW to 10 MW, and greater than 10 MW.
- Inverter or rotating machine based DER – Each has unique technology related commissioning requirements
- DER unit/system lab certification, partial certification, or not certified – Lab certified inverter based DER units and DER systems are available. Rotating machines and some inverters are not lab certified. DER systems may not be certified even though they use certified DER units. The use of non-certified or partially certified DER units/systems will extensively increase the commissioning requirements.
- Exporting or non-exporting – DER units/systems that export power will have more extensive commissioning requirements.
- Radial distribution or area/spot network – Area/spot networks have more stringent commissioning requirements than radial distribution networks.

14.6.3. Required Witness Tests

Before parallel operation with the Utility System, and after completion of commissioning tests, additional witness testing may be required and inspected by Utility. The IC is responsible for providing qualified personnel who will complete all required tests. Witness testing is generally required for larger generators. Utility reserves the right to require witness testing in all DER Interconnected scenarios. The following table identifies witness tests that must be performed in accordance with requirements described above.

Applicability	Test	Description
If telemetry required	Cease to energize and trip test	Send command to cease to energize and trip the DER and measure time to shut off.
	Anti-islanding	Open isolation device and measure time for inverter to shut off - ≤ to 2 seconds
All sizes	Reconnection Test	5-minute delay before reconnection. During testing open 3 phase source multiple times after initial opening to verify remains disconnected for at least 5 minutes. – Stay disconnected for ≥ 5 minutes
Required for systems over 25kW	Load Rejection Overvoltage Test	DER facility must cease to energize and trip within 120 cycles after loss grid or: o Maximum RMS Voltage Produced by DER at PCC ranging from 1.1 p.u. to 1.2 p.u. must not exceed 60 cycles o Maximum RMS Voltage Produced by DER at PCC ranging from 1.21 p.u. to 1.5 p.u. must not exceed 10 cycles o Maximum RMS Voltage Produced by DER at PCC ranging from 1.51 p.u. to 2.0 p.u. must not exceed 3 cycles
Where system output must be limited to a certain value	Power Limit Function	Set power limit below current power export. Record response to power limit.
Required for systems over 25kW	Radio Frequency Interference Test	Use a handheld AM Radio to determine if there is RFI during inverter output. RFI will generally increase as inverter output increases but does not go away until inverter shuts off.
Required for systems over 25kW	Current harmonics test	Measured at the PCC
If telemetry required	Telemetry/SCADA	Measured values include kV, Amps, and kW
Required for systems over 25kW	Primary Metering	Measured values include kV, Amps, and kW
Test required if system GT 500 kW and primary voltage LT 5kV, GT 3 MW for voltages GE 5kV and LT 15 kV, GE 4 MWs for voltages GE 1 kV and LT 30 kV, and GE 5 MWs for voltages GE 30 kV and LE 69kV	Primary PTs for Ground Fault Protection	PHI primary PT's shall be wired to customer load side relay to provide Device 59G or Device 27/59 protection for Area EPS Faults - Identify relay manufacturer, model, and applied relay settings in P.U. (kW) and T.D. (Seconds). - Identify relay test values and measure values in P.U. (kW) and T.D. (Seconds)
Where DTT required	Direct Transfer Trip (DTT)	Confirm DTT signal trips customer protective device to isolate DER.
Required for non-exporting customers	Reverse Power Relay (Device 32)	Installed at the PCC - Identify relay manufacturer, model, and applied relay settings in P.U. (kW) and T.D. (Seconds). - Identify relay test values and measure values in P.U. (kW) and T.D. (Seconds) - Verify DER either trips off or isolates to prevent export of power to the Area EPS at the PCC.

Special commissioning and witness test requirements for secondary networks can be found in Section 11.1.2 – Special Review and Witness Testing for Networks.

14.7. Recommissioning

Recommissioning is required, under certain circumstances, after the original commissioning and witness testing is completed. The extent of recommissioning is dependent on the reason for the commissioning and the effect on the DER interconnection. Partial recommissioning may be required as part of the regular testing of basic functionalities of protective and control functions. These tests are expected and may need to occur in time frames typically ranging from every year to every 10 years depending on manufacturers recommendations and PHI's experience with similar equipment. Section 14.5 has further information on periodic testing.

Circumstances that may lead to event-based DER recommissioning include:

- Change in version of software, software or parameter modifications that change rated values,
- Replacement of major components or modules with a new version,
- Required changes in the plant telemetry, or changes in major equipment (e.g. transformers, circuit breakers, etc.),
- Change in operating mode that was not previously commissioned.

Recommissioning may be scheduled, triggered based on notification of plant change requirements may occur due to automated notices of operation outside of expected parameters. These may include mis operation of the DER, mis operation of protective systems, or excess harmonics are detected at the PCC. PHI will determine whether recommissioning may require the full set of tests required of a new facility or a subset of these tests will be sufficient. The level of testing is dependent on the reason for the recommissioning.

14.8. Periodic O&M and Testing

14.8.1. Periodic testing Requirements

The IC must provide PHI with calibration and functional test data for the associated equipment upon request. Minimum intervals are indicated below:

Device	Frequency
Relays	Every three years
Communication Channels	Every three years
Circuit breakers	Every three years
Batteries	Per IEEE 450 - 1995 Standard

The customer must include the identities and qualifications of the personnel who performed the tests. Utility personnel may need to periodically witness the testing.

Additional requirements for periodic testing are specified in IEEE Std 1547™-2018 clause 11.2.6 - Periodic Tests and Verifications. These requirements include changes in functional software or firmware changes, changes in hardware components of the DER, and changes in protection functions or settings.

14.8.2. Operating and Maintenance Requirements

Utility routinely performs maintenance on its system. While the Utility tries to perform all maintenance on a scheduled basis, sometimes emergency maintenance is necessary. For both scheduled and emergency maintenance, the work is generally planned to minimize both customer inconvenience and company cost. As a prudent cost control, the Utility schedules most routine maintenance during normal daylight working hours. To this end, the Utility routinely transfers customer load among electric sources, so that the customers involved remain in service while the maintenance work is being performed. For most customers involved this “switching” is transparent.

When a customer is operating a generator in parallel with the electric system, it may not be possible to do a load transfer with large DERs remaining in service. If the situation is not an emergency, possible action may include the following:

- The customer may choose to turn off the generation and continue electric consumption. Electricity may be purchased from Utility under the provisions of the Standby Service Rate.
- The customer may choose to turn off the generation while curtailing electric consumption. Electricity may also be purchased from Utility under the provisions of the Standby Service Rate.
- The customer may request Utility to perform the work at times when the customer’s generation is not being operated. The customer is responsible for, and will be billed for, the full extra cost that Utility experiences due to the request.
- The customer’s generation and load may be switched away from the Utility System while the work is in progress. This option is available only if the customer’s electric system can operate independently of the Utility System. Notwithstanding the above, switching equipment capable of isolating the customer’s generation from Utility shall be accessible to and under the exclusive control of Utility always. At its option, Utility may choose to operate the switching equipment if, in Utility’s opinion, continued operation of the customer’s generation in connection with Utility’s system may create or contribute to a system emergency, an unsafe condition, or interfere with service to other customers.

The switching equipment referred to above must be accessible to and capable of being operated and locked by Utility personnel. This equipment must provide a visible break in the circuit.

15. Appendix A: Reference Standards and Guidelines

Industry Standards

- IEEE Standards 1547, 519, 1453
- ANSI C84.1, C62.92, C37
- UL 1741

Federal Guidelines

- FERC Small Generator Interconnection Procedures (SGIP)

ISO Rules (Large Interconnections and Wholesale Market)

- PJM Manual 14A – New Service Requests
- PJM Manual 14G – Generation Interconnection Requests
- PJM Manual 01 – Control Center and Data Exchange Requirements
- PJM Manual 14D, Generator Operational Requirements

State Rules (Small Interconnections and NEM)

- Delaware: Delaware Code "Title 26 – Public Utilities"
- Maryland: Maryland Public Service Commission Title 20, Subtitle 50 "Service Supplied by Electric Companies", Chapter 9 "Small Generator Interconnection Standards"
- New Jersey: New Jersey Administrative Code Title 14 "Public Utilities", Chapter 8 "Renewable Energy and Energy Efficiency", Subchapter 5 "Interconnection of Class I Renewable Energy Systems"
- Washington, D.C.: D.C. Municipal Regulations Title 15 "Public Utilities and Cable Television", Chapter 15-40 "District of Columbia Small Generator Interconnection Rules"

Industry Association Guidelines

- CBEMA and ITIC Requirements
- IREC Guidelines, Solar ABCs

EU/PHI Technical References

- Distribution System Planning and Design Criteria for PHI
- Technical Considerations Covering Parallel Operations of Customer Owned Generation
- Exelon Utilities Transmission Facility Interconnection Requirements
- Electric Service Handbook / Service Brochures | Atlantic City Electric/Pepco/Delmarva Power

16. Appendix B: Common DER Configurations

<table>
<tr><th colspan="7">Common DER Configurations</th></tr>
<tr><td rowspan="3">Config 1</td><td rowspan="3">25 kW or less</td><td>Config 1A</td><td>Lab Certified</td><td>Inverter Based</td><td>Radial</td><td rowspan="2">Exporting or Non-Exporting</td></tr>
<tr><td>Config 1B</td><td>Not Lab Certified</td><td rowspan="2">Inverter or rotating machine</td><td>Radial</td></tr>
<tr><td>Config 1C</td><td>Lab certified or Not Lab Certified</td><td>Area or Spot Network</td><td>Non-Exporting</td></tr>
<tr><td rowspan="6">Config 2</td><td rowspan="6">>25 kW and ≤250 kW</td><td>Config 2A</td><td rowspan="2">Lab Certified</td><td rowspan="2">Inverter Based</td><td rowspan="4">Radial</td><td>Exporting</td></tr>
<tr><td>Config 2B</td><td>Non-Exporting</td></tr>
<tr><td>Config 2C</td><td rowspan="2">Not Lab Certified</td><td rowspan="4">Inverter or rotating machine</td><td>Exporting</td></tr>
<tr><td>Config 2D</td><td rowspan="3">Non-Exporting</td></tr>
<tr><td>Config 2E</td><td>Lab Certified</td><td rowspan="2">Area or Spot Network</td></tr>
<tr><td>Config 2F</td><td>Not Lab Certified</td></tr>
<tr><td rowspan="6">Config 3</td><td rowspan="6">>250 kW and ≤2000 kW</td><td>Config 3A</td><td rowspan="2">Lab Certified</td><td rowspan="2">Inverter Based</td><td rowspan="4">Radial</td><td>Exporting</td></tr>
<tr><td>Config 3B</td><td>Non-Exporting</td></tr>
<tr><td>Config 3C</td><td rowspan="2">Not Lab Certified</td><td rowspan="4">Inverter or rotating machine</td><td>Exporting</td></tr>
<tr><td>Config 3D</td><td rowspan="3">Non-Exporting</td></tr>
<tr><td>Config 3E</td><td>Lab Certified</td><td rowspan="2">Area or Spot Network</td></tr>
<tr><td>Config 3F</td><td>Not Lab Certified</td></tr>
<tr><td rowspan="4">Config 4</td><td rowspan="4">>2 MW and ≤10 MW</td><td>Config 4A</td><td rowspan="2">Lab Certified</td><td rowspan="2">Inverter Based</td><td rowspan="4">Radial</td><td>Exporting</td></tr>
<tr><td>Config 4B</td><td>Non-Exporting</td></tr>
<tr><td>Config 4C</td><td rowspan="2">Not Lab Certified</td><td rowspan="2">Inverter or rotating machine</td><td>Exporting</td></tr>
<tr><td>Config 4D</td><td>Non-Exporting</td></tr>
<tr><td rowspan="4">Config 5</td><td rowspan="4">>10 MW</td><td>Config 5A</td><td rowspan="2">Lab Certified</td><td rowspan="2">Inverter Based</td><td rowspan="4">Radial</td><td>Exporting</td></tr>
<tr><td>Config 5B</td><td>Non-Exporting</td></tr>
<tr><td>Config 5C</td><td rowspan="2">Not Lab Certified</td><td rowspan="2">Inverter or rotating machine</td><td>Exporting</td></tr>
<tr><td>Config 5D</td><td>Non-Exporting</td></tr>
</table>

17. Appendix C: Typical One-Line Diagrams

The following One-Line Diagrams are intended to be typical or representative samples of various types and sizes of generation Facilities that are connected to and operate in parallel with the PHI Power Delivery System and do not purport to cover every possible case. Each site will have to be specifically designed considering the unique characteristics of each installation, the specific location of the Point of Common Coupling and the operating and contractual requirements for that site. Additional PJM and NERC requirements may also apply.

The listed voltages on the diagrams represent nominal values. The actual voltage is dependent on the interconnection location on the PHI circuit.

Below are the one-line requirements for 50kW and greater capacity

Drawing needs to be an “engineering” oneline drawing if the application is 100KW or above or customer is primary metered. “Engineering” means no block diagrams, drawing symbology should use generally accepted notation in the power and electrical engineering industry and any drawings stamped by a PE will automatically pass criteria #1. The drawings should be legible and be a separate digital PDF print (do not combine the application, inverter spec sheet, panel spec sheet, etc with the engineering oneline); a scanned hand or CAD drawings is not acceptable.

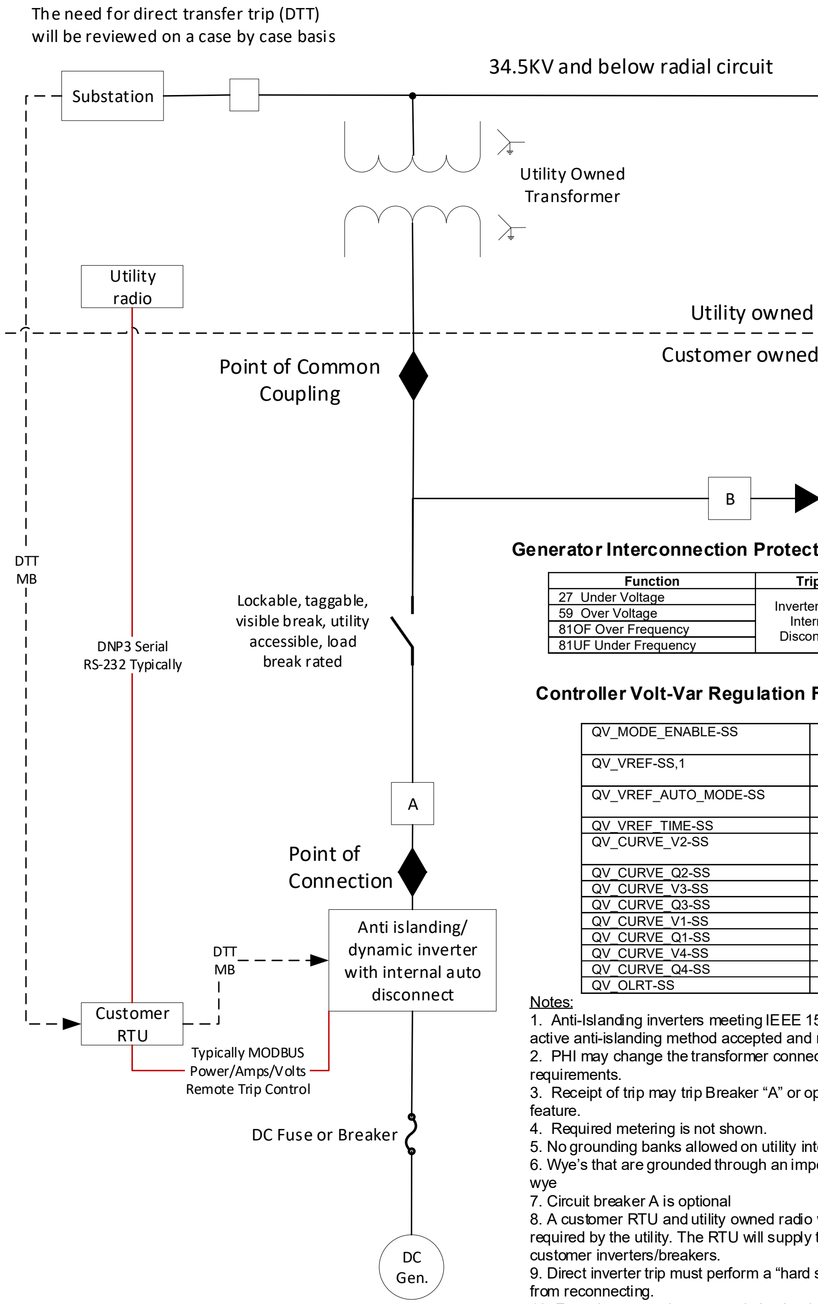
- The generator disconnect switch if required should be explicitly labeled on the oneline as “lockable, taggable, capable of breaking load current, visible break and utility accessible”. Write next to the switch if it is located indoors or outdoors. These requirements written on the single line may be modified for each site depending on the jurisdictional requirements for switches. This should reflect the actual design in the field.
- The drawing at a minimum should show the point of generator connection and the electrical path back to the point of common coupling POI with the utility (up to the utility metering point).
- Any customer dual (backup) feeds, networked feeds or split feeds with the utility supply should be shown on the drawing. Any interlock schemes or systems to prevent the generation from operating on the second feed should be illustrated on the engineering oneline and labeled as such.
- If the customer is required to provide reactive power support such as constant power factor or volt-var, then the customer must show on the single line drawing the voltage transformer that monitors the voltage at the point of interconnection performing the volt-var function.
- All Customer owned transformers should be labeled with the appropriate transformer connection type on both primary, secondary, and tertiary side. (WyeG, Wye, Delta, etc.) Additionally, the transformer turns ratio, positive and zero sequence impedance, magnetization zero sequence impedance, the number of cores and type construction (shell/core) and nameplate should be labeled (12kV/480, 480/120,200KW, 5%, 8%, etc.). In Pepco, 5-core grounded wye- grounded ground wye transformers will be required. In ACE/DPL, if utilizing a wye grounded connection on the medium voltage side facing the utility, it is required that the Customer procure a 5-core transformer and to not configure the low voltage winding in Delta. In ACE/DPL, if utilizing an ungrounded winding on the medium voltage side facing the utility, there is an additional requirement of the Customer to install 3-phase potential transformers for overvoltage protection on the medium voltage side of the transformer. The single-line diagram must indicate the 3-phase PTs and the wiring to the relay, the relay must show the model number and indicate that it will be performing (59) overvoltage protection, and the tripping connections from the relay to a generator breaker or

each inverter directly. The overvoltage protection settings must be as follows: 110% at 60 cycle delay and 120% at 0 cycle delay. The overvoltage settings must be indicated on the single-line diagram.Any Customer relaying schemes that are required by the Company or affect the Company's system should illustrate the connections between: the relay, any inputs or transducers to the relay, and any outputs from that would affect the generation system or the connection between the Company and the Customer. Show current transformer and voltage transformer/reference on drawing and connections to associated relays. List equipment rating adjacent to specific instrument. A switch shall be installed in the secondary circuit between each instrument transformer and the relay the instrument transformer is supplying. The following are approved test switches: FT Type test Current, 6 pole and Voltage test switch, 4 pole, ABB (Westinghouse) Style 498A010G01 or equivalent. Customer Generations must disconnect in the event of loss of total protection (i.e., relay fail alarm)

- Voltage Reactive Power (Volt-Var) or Voltage Active Power Control Regulation – the singleline drawing must show the settings required by the PHI utility on the singleline drawing in a table that references the device(s) implementing the control regulation setting. For all applications the point of three phase voltage measurement must be clearly labeled at the RPA. The instrumentation devices required to measure this voltage such as three phase instrumentation transformers must be shown on the singleline drawing as well as their connections to a centralized controller, etc that implements the regulation support. The connection between the centralized controller and inverter(s) should also be shown and labeled.
- Power Control Systems (PCS) – the singleline drawing must show the settings required by the PHI utility on the single line drawing in a table that references the devices() implementing the PCS system. This includes the export limit(s) next to the PCS controller, and/or the curtailment setting on a any PV or battery inverters.
- The customer oneline will show all pertinent connections and equipment that implement utility transfer trip and/or remote trip schemes. The online drawings should clearly illustrate what breaker, inverter, switch, etc the incoming utility trip signal is tripping and the relay or RTU performing the trip function. Additionally, if generator telemetry is required, the customer oneline should show where the RTU is measuring the telemetry (CTs, PTs, connection to an inverter or accumulator, etc).
- A reliable power source should supply Customer relays, [IF Telemetry is required], telemetry meters/RTU and PHI telemetry equipment shall also be supplied. Any means of disconnecting a solar site shall not cause immediate loss power to critical monitoring devices.
- For larger interconnections with more complicated control and protection schemes, schematics/elementary drawings may be requested for supplemental information.
- Furthermore, any revision to the customer oneline that constitutes a design change that affects an utility requirement or criteria after the technical review (30 days) is completed will require that the customer re-submit their application. These changes include but are not limited to:
    - Change in generator AC system size
    - Change in generator connection point
    - Change in point of common coupling POI
    - An addition of a customer owned transformer or a change in the transformer connection type (delta, wye, etc.)

Removal or change of the type of generator disconnect switch (if required)

17.1. Diagram 1 – Typical DC Generator Connected via Company-owned Transformer



Generator Interconnection Protection Functions

Function	Trips	Setting
27 Under Voltage	Inverter Auto Internal Disconnect	Set per PHI TIR
59 Over Voltage		
81OF Over Frequency		
81UF Under Frequency		

Controller Volt-Var Regulation Functions at PCC

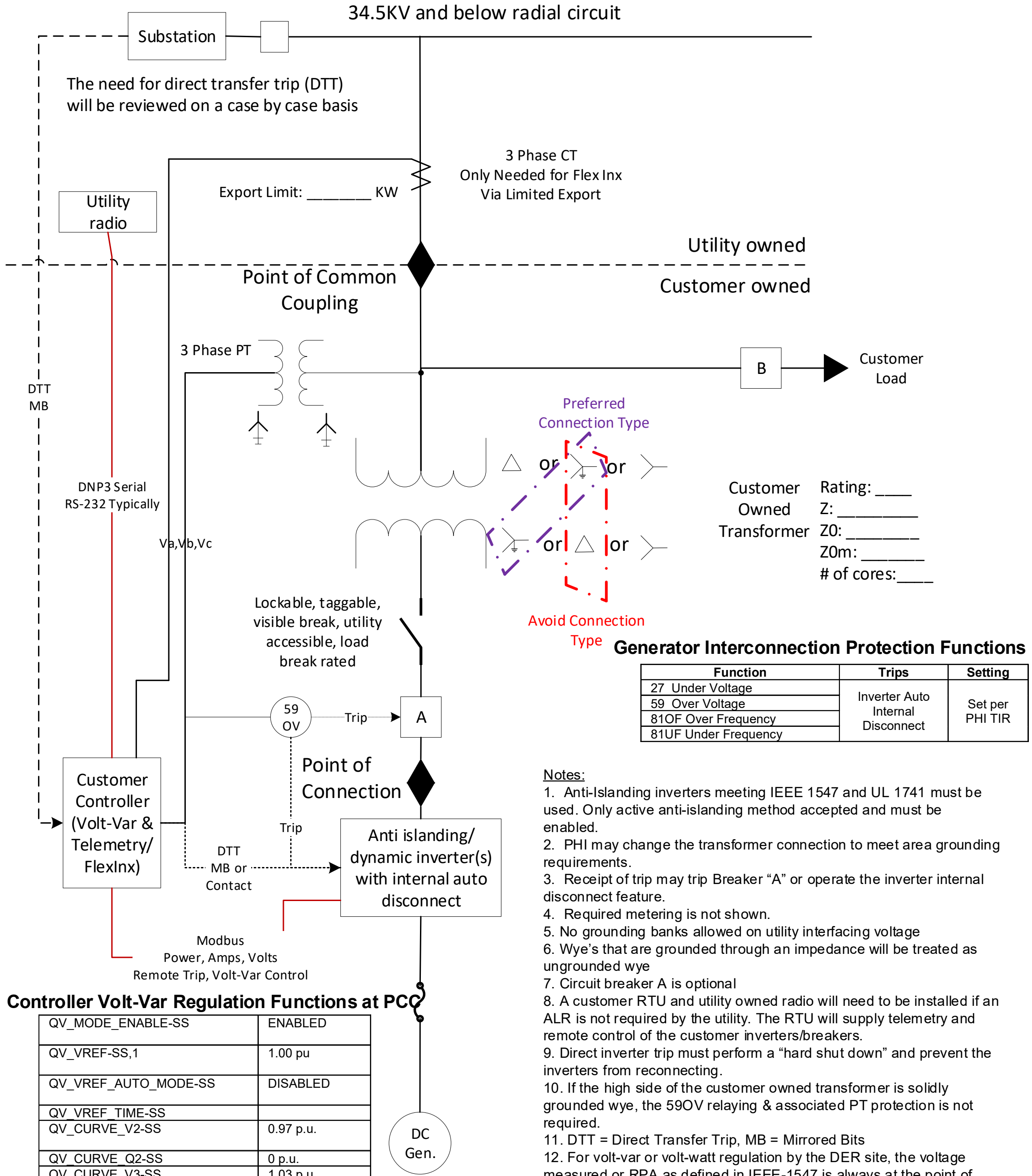
QV_MODE_ENABLE-SS	ENABLED
QV_VREF-SS,1	1.00 pu
QV_VREF_AUTO_MODE-SS	DISABLED
QV_VREF_TIME-SS	
QV_CURVE_V2-SS	0.97 p.u.
QV_CURVE_Q2-SS	0 p.u.
QV_CURVE_V3-SS	1.03 p.u.
QV_CURVE_Q3-SS	0 p.u.
QV_CURVE_V1-SS	0.91 p.u.
QV_CURVE_Q1-SS	0.44 p.u.
QV_CURVE_V4-SS	1.09 p.u.
QV_CURVE_Q4-SS	-0..44 p.u.
QV_OLRT-SS	5 s

Notes:

1. Anti-Islanding inverters meeting IEEE 1547 and UL 1741 must be used. Only active anti-islanding method accepted and must be enabled.
2. PHI may change the transformer connection to meet area grounding requirements.
3. Receipt of trip may trip Breaker “A” or operate the inverter internal disconnect feature.
4. Required metering is not shown.
5. No grounding banks allowed on utility interfacing voltage
6. Wye’s that are grounded through an impednace will be treated as ungrounded wye
7. Circuit breaker A is optional
8. A customer RTU and utility owned radio will need to be installed if an ALR is not required by the utility. The RTU will supply telemetry and remote control of the customer inverters/breakers.
9. Direct inverter trip must perform a “hard shut down” and prevent the inverters from reconnecting.
10. For volt-var or volt-watt regulation by the DER site, the voltage measured or RPA as defined in IEEE-1547 is always at the point of common coupling aka the point of interconnection. The customer controller shall implement the volt-var regulation per IEEE-1547-2018. See 4.3 Applicable voltages and chapter 5.

Figure 3, Typical NEM Type DC Generator Connected via Utility Owned Transformer

17.2. Diagram 2 – Typical DC Generator with Customer-owned Transformer



Generator Interconnection Protection Functions

Function	Trips	Setting
27 Under Voltage	Inverter Auto Internal Disconnect	Set per PHI TIR
59 Over Voltage		
81OF Over Frequency		
81UF Under Frequency		

Controller Volt-Var Regulation Functions at PCC

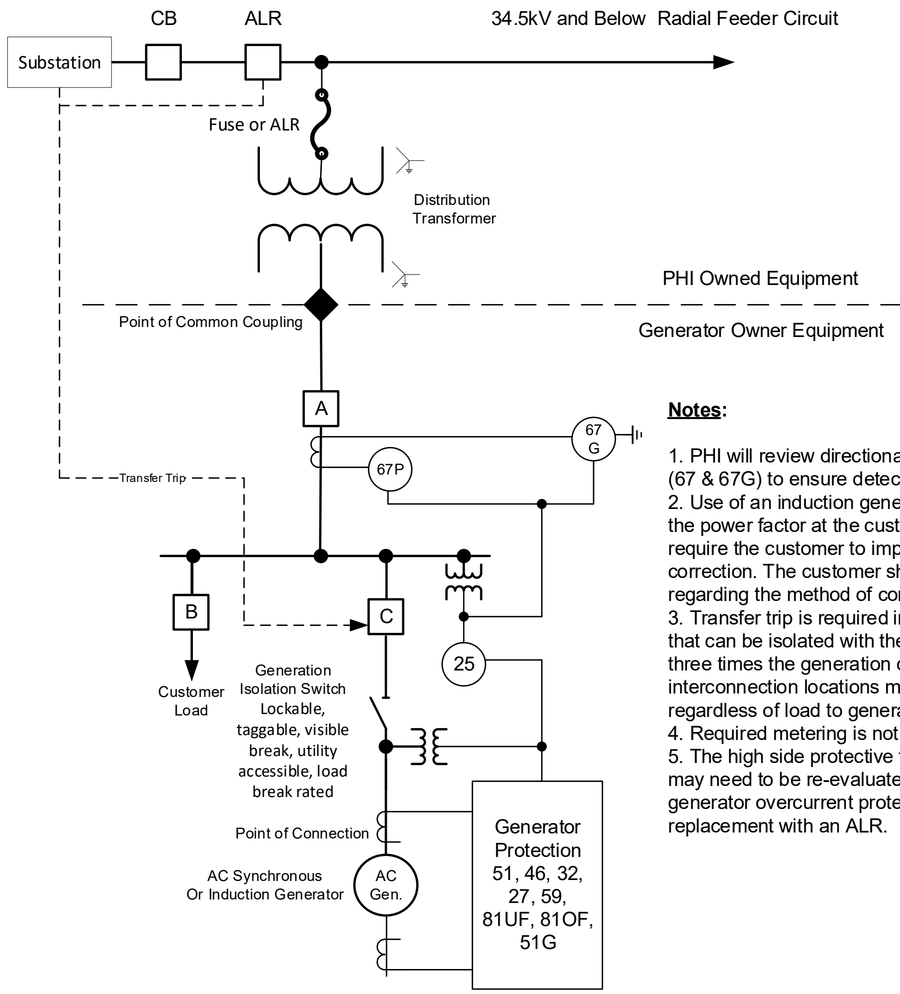
QV_MODE_ENABLE-SS	ENABLED
QV_VREF-SS,1	1.00 pu
QV_VREF_AUTO_MODE-SS	DISABLED
QV_VREF_TIME-SS	
QV_CURVE_V2-SS	0.97 p.u.
QV_CURVE_Q2-SS	0 p.u.
QV_CURVE_V3-SS	1.03 p.u.
QV_CURVE_Q3-SS	0 p.u.
QV_CURVE_V1-SS	0.91 p.u.
QV_CURVE_Q1-SS	0.44 p.u.
QV_CURVE_V4-SS	1.09 p.u.
QV_CURVE_Q4-SS	-0..44 p.u.
QV_OLRT-SS	5 s

Notes:

1. Anti-Islanding inverters meeting IEEE 1547 and UL 1741 must be used. Only active anti-islanding method accepted and must be enabled.
2. PHI may change the transformer connection to meet area grounding requirements.
3. Receipt of trip may trip Breaker “A” or operate the inverter internal disconnect feature.
4. Required metering is not shown.
5. No grounding banks allowed on utility interfacing voltage
6. Wye’s that are grounded through an impedance will be treated as ungrounded wye
7. Circuit breaker A is optional
8. A customer RTU and utility owned radio will need to be installed if an ALR is not required by the utility. The RTU will supply telemetry and remote control of the customer inverters/breakers.
9. Direct inverter trip must perform a “hard shut down” and prevent the inverters from reconnecting.
10. If the high side of the customer owned transformer is solidly grounded wye, the 59OV relaying & associated PT protection is not required.
11. DTT = Direct Transfer Trip, MB = Mirrored Bits
12. For volt-var or volt-watt regulation by the DER site, the voltage measured or RPA as defined in IEEE-1547 is always at the point of common coupling aka the point of interconnection. The customer controller shall implement the volt-var regulation per IEEE-1547-2018. See 4.3 Applicable voltages and chapter 5.

Figure 2, Typical NEM/Community Type DC Generator Connected via Customer Owned Transformer with Volt-Var and Telemetry

17.3. Diagram 3 – Typical AC Generator with Company-owned Transformer



Notes:

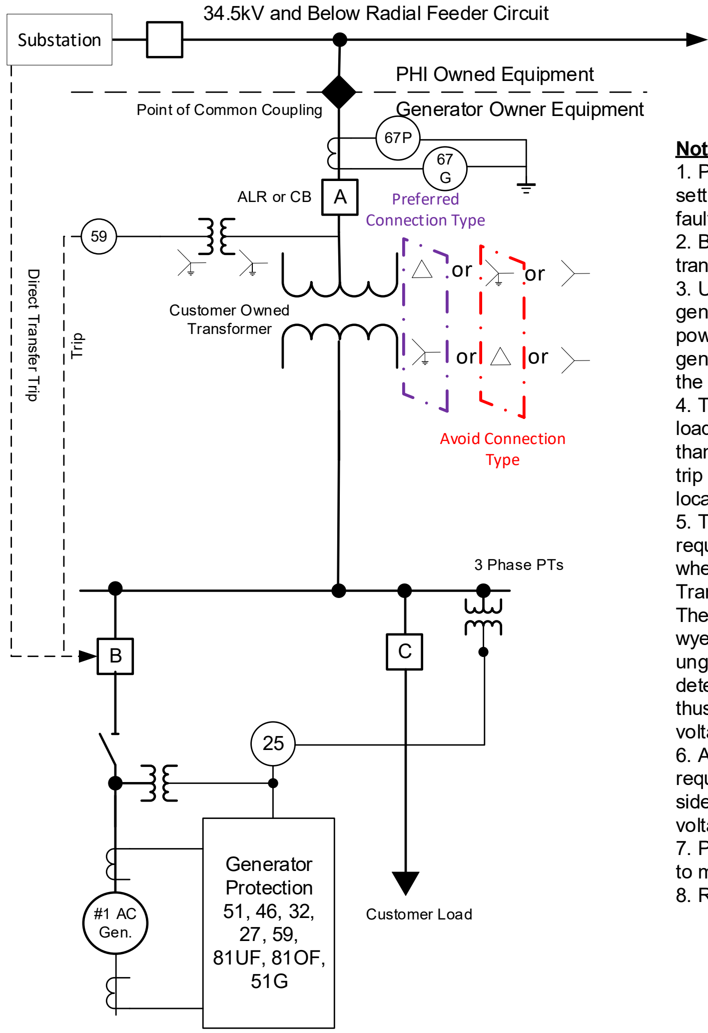
1. PHI will review directional over current relay settings (67 & 67G) to ensure detection of PHI circuit faults.
2. Use of an induction generator may adversely affect the power factor at the customer location. This will require the customer to implement power factor correction. The customer should consult with PHI regarding the method of correction.
3. Transfer trip is required in cases where the net load that can be isolated with the generation is less than three times the generation capacity. Some interconnection locations may require transfer trip regardless of load to generation ratio.
4. Required metering is not shown.
5. The high side protective fuse on the PHI transformer may need to be re-evaluated and coordinated with the generator overcurrent protection and may require replacement with an ALR.

Generator & Interconnection Protective Functions

Function	Action	Setting
25 Gen. Check Synch	Supervises Breaker C Close	Per Generator Manufacturer Limits
27 Gen. Under Voltage	Trips Breaker C or A	Per IEEE 1547
32 Gen. Anti-Motoring	Trips Breaker C	Per IEEE Std. C37.102
46 Gen. Neg. Seq.	Alarm, then Trips Breaker C	Per IEEE Std. C37.102
59 Gen Over Voltage	Trips Breaker C or A	Per IEEE 1547 – 2003
51 Gen. Over Current	Trips Breaker C	Per IEEE Std. C37.102
51G Gen. Ground OC	Trips Breaker C	Per IEEE Std. C37.101
67 Brk. Dir. Over Current	Trips Breaker C	Set in Consultation with PHI
67G Brk. Dir. Grd. OC	Trips Breaker C	Set in Consultation with PHI
81UF Gen. Under Freq.	Trips Breaker C or A	Per IEEE 1547
81OF Gen. Over Freq.	Trips Breaker C or A	Per IEEE 1547
High Side 27UV/59OV	Trips Breaker C	Set by PHI
Transfer Trip	Trips Breaker C	Transfer Trip Initiate Set by PHI

Figure 4, Typical AC Generator with Company Owned Transformer

17.4. Diagram 4 – Typical AC Generator with Customer-owned Transformer



Notes:
1. PHI will review directional over current relay settings (67 & 67G) to insure detection of PHI circuit faults. 67 elements should trip breaker A
2. Breaker A designed to close only to a hot transformer and a dead low side bus.
3. Use of induction generators will require the generator owner to take corrective action if the power factor does not meet tariff requirements. The generator owner should consult with PHI regarding the method of power factor correction.
4. Transfer trip is needed in cases where the net load that can be isolated with the generation is less than three times the generation capacity. Transfer trip may be needed at some interconnection locations regardless of load to generation ratio.
5. Three phase to ground voltage sensing is required for the 27UV/59OV protective functions when the high side of the customer Interface Transformer is connected ungrounded wye or delta. These protective functions are also required for a wye-wye transformer when the generators are ungrounded. These functions provide high speed detection of a grounded high side conductor and thus prevent equipment damage due to high voltage.
6. Aggregate site generation greater that 2 MW will require voltage and frequency protection in the high side ALR/Breaker if dynamic studies have shown voltage regulation concerns.
7. PHI may require specific transformer connections to meet area grounding requirements.
8. Required metering is not shown.

Generator & Interconnection Protective Functions

Function	Action	Setting
25 Gen. Check Synch	Supervises Brk. B & C Close	Per Generator Manufacturer Limits
27 Gen. Under Voltage	Trips Generator Breaker	Per IEEE 1547
32 Gen. Anti-Motoring	Trips Generator Breaker	Per IEEE Std. C37.102
46 Gen. Neg. Seq.	Alarm, then Trips Gen. Brk.	Per IEEE Std. C37.102
59 Gen Over Voltage	Trips Generator Breaker	Per IEEE 1547 – 2003
51 Gen. Over Current	Trips Generator Breaker	Per IEEE Std. C37.102
51G Gen. Ground OC	Trips Generator Breaker	Per IEEE Std. C37.101
67 Brk. Dir. Over Current	Trips Breaker A	Set in Consultation with PHI
67G Brk. Dir. Grd. OC	Trips Breaker A	Set in Consultation with PHI
81UF Gen. Under Freq.	Trips Breaker A or B & C	Per IEEE 1547
81OF Gen. Over Freq.	Trips Breaker A or B & C	Per IEEE 1547
Transfer Trip	Trips Breaker A or B & C	Trip Initiation Set by PHI
High Side 27UV/59OV	Trips Breaker A or B & C	Set in Consultation with PHI

Figure 5, Typical AC Generator with Customer Owned Transformer

18. Appendix D: Typical Relay Requirements per Plant Configuration (Radial Circuits)

Common DER Configurations			*These are general guidelines for protection requirements and may vary based on IC's total system configuration. Individual protective device functions may be implemented using multifunction relay.+*					
Config 1a	**Config 2a, 2b, 3a, 3b, 4a, 4b**	**Config 1b**	**Config 2d, 3d, 4d**	**Config 1c, 2e, 2f**	**Config 2b, 2d, 3b, 3d, 4b, 4d**	**Config 2c, 2d, 3c, 3d, 4c, 4d**	**Config 1c, 2e, 2f**	**Config 2a, 2b, 2c, 2d, 3a, 3b, 3c, 3d, 4a, 4b, 4c, 4d, 5a, 5b, 5c**
11 - Multifunction Device/Relay - Required protective functions may be implemented in a single multifunction relay								
	✓		✓	✓	✓	✓	✓	✓
21 - Distance or Impedance - Requirement determined by capacity. Does not apply to inverter-based generation								
			✓ Other directional protection may be utilized in lieu.		✓	✓ Other directional protection may be utilized in lieu.	✓	✓
25 - Synchronizing or Synchronism Check (Customer DER location) – May only be required for rotating equipment								
		✓	✓	✓	✓	✓	✓	✓
25 - Synchronizing or Synchronism Check/Backfeed Detection (PHI substation)								
	✓ May be required when aggregate of all generation exceeds 2 MW per feeder, depending on capacity, to provide back feed detection.		✓ May be required depending on capacity, to provide back feed detection.	✓ May be required depending on capacity, to provide back feed detection.	✓ May be required for inverter-based generation, depending on capacity, to provide back feed detection.	✓ May be required depending on capacity, to provide back feed detection.	✓ May be required for inverter-based generation, depending on capacity, to provide back feed detection.	✓ May be required for inverter-based generation, depending on capacity, to provide back feed detection.
51N - Neutral Time Overcurrent*								
			✓	✓	✓	✓	✓	✓

Config 1a	Config 2a, 2b, 3a, 3b, 4a, 4b	Config 1b	Config 2d, 3d, 4d	Config 1c, 2e, 2f	Config 2b, 2d, 3b, 3d, 4b, 4d	Config 2c, 2d, 3c, 3d, 4c, 4d	Config 1c, 2e, 2f	Config 2a, 2b, 2c, 2d, 3a, 3b, 3c, 3d, 4a, 4b, 4c, 4d, 5a, 5b, 5c
51V - Voltage Restrained/Controlled Time Overcurrent* - May be required depending on capacity.								
			✓		✓	✓	✓	✓
67V - Voltage Restrained/Controlled Directional Time Overcurrent* - May be required for inverter-based generation.								
	✓		✓		✓	✓	✓	✓
81O - Over frequency* - May also be required in a separate relay depending on capacity. Over frequency protection is part of lab certified equipment.								
✓	✓	✓	✓	✓	✓	✓	✓	✓
81U - Under frequency* - May also be required in some configuration to accommodate a separate relay, depending on capacity. Under frequency is a part of lab certified equipment.								
✓	✓	✓	✓	✓	✓	✓	✓	✓
86 - Lock-Out								
			✓		✓	✓	✓	✓
87 - Current Differential* - May be required based on system configuration								
			✓		✓	✓	✓	✓
Power Transformer - As required for system interconnection								
	✓	✓	✓	✓	✓	✓	✓	✓
Interrupting device - May be required for inverter-based generation depending on capacity and transformer								
	✓	✓	✓	✓	✓	✓	✓	✓
Breaker Failure backing tripping (BF)								
			✓		✓	✓	✓	✓
Relay Failure Protection/Alarm - May be required if there is a separate protective relay.								
	✓		✓		✓	✓	✓	✓

19. Appendix E: General Protection Requirements

The PHI Power Delivery System is subject to a variety of natural and man-made hazards. Among these are lightning, wind, snow, animals, vehicular-pole accidents, vandalism and human error. These same hazards are present in residential and commercial electric systems but to a lesser degree due to the smaller size and protected environment of these systems. The electric problems that can result from the preceding hazards are principally short circuits, grounded conductors and broken or open conductors. All of these problems require that the affected equipment be de-energized as quickly as possible to minimize equipment damage, to protect grid security, to lessen the adverse impact on customers and to remove any hazard to the public and company personnel. When customer owned generators are connected to and operate in parallel with the grid, the generator owner has the responsibility to protect both their own facility and the grid from the impact of the generator owner’s facility.

The protection system at the Point of Common Coupling should be designed and operated with the following desired goals in mind:

- Protect the PHI Power Delivery System from the adverse impacts of the parallel generator and from faults within the customer’s facility.
- Protect the parallel generator from faults or other disturbances in the PHI Power Delivery System.
- Disconnect the parallel generator from the PHI Power Delivery System for abnormal operating conditions.
- Permit the desired range of power transfer without false operation.

The protection schemes described in this section are intended to be typical for illustration purposes and not specific design requirements for any plant site or configuration. They are intended to guide the proposed Generator Owner and provide basic information on the types of protection schemes necessary for generator Parallel Operation. These refer to plant rating as well as the PHI distribution feeder voltage.

19.1. General Requirements

- Protective relays, wherever possible, shall be microprocessor type with integral trip record and fault recording, self-checking and remote communication.
- All protective relays must have the desired sensitivity and speed for its intended application and be of utility grade.
- Primary and backup protection schemes shall be supplied via independent current/potential circuits and independently protected DC control circuits.
- DC circuits supplying protective relaying schemes shall be continuously monitored and fused separately from any other DC control circuits. Loss of any control power bus including DC trip and close busses of each breaker shall also be monitored and alarmed to a manned location so that corrective action can be taken. Relay failure alarms shall be handled in a similar manner.

PHI DER Technical Interconnection Requirements

- The Generator Owner must install an uninterruptable power supply (UPS) capable of supplying power to the Generator Owner's frontline and backup relay protection systems during utility power outages, whether sustained or momentary.
- The generator and Point of Common Coupling protection relay schemes shall be continuously monitored and in a functional state. The generator shall immediately be disconnected from the Company Grid for any condition that would make the protection scheme inoperable.
- The operating power for the generator and Point of Common Coupling protection relay schemes and the control power used to disconnect the generator from the Company Grid must not be dependent on Company Grid power.
- The generator shall be equipped with protective equipment (hardware or software) to prevent the generator from energizing a de-energized PHI Power Delivery System circuit.
- Protection at the Point of Common Coupling must detect and isolate the Facility from the PHI Power Delivery System for a fault condition in the Generation Owner's Facility.
- Protection at the Point of Common Coupling must detect and isolate the Generator Owner's Facility from the Company Grid for a fault condition on the PHI Power Delivery System circuit that supplies the Customer generator site.
- The protection scheme should permit the desired range of power transfer without false operation. The protection scheme should also prevent excessive or unnecessary tripping that would adversely affect the Company's service reliability to other Customers or Generator Owners.
- The Generator Owner's protection must recognize and disconnect the Generator from the Company Grid if the generator is to Island with other Customer load. Exceptions are those generators with specific contractual obligations to supply other Customer load and who have installed the necessary equipment to control and stabilize voltage and frequency within the Island.
- The Generator Owner is responsible for protecting their generator and all interconnection / ancillary equipment. This includes any line extensions owned by the Generator Owner. The Generator Owner must supply and own the required protection schemes and fault interrupting devices along with the necessary monitor/control requirements specified either by PHI Power Delivery or PJM.

Note: This preceding list of design requirements is not intended to be all-inclusive. Other hazards and conditions may need to be taken into consideration by the design engineer based upon the circumstances, the specific site, the Generation Owner's needs and other appropriate criteria.

19.2. Interface (Isolation) Transformer Protection

Typical protection schemes for various size Interface Transformers are illustrated below.

Interface Transformer Protection Up to 10 MVA	10 – 50 MVA	Greater than 50 MVA
□ High speed protection(Time/Inst. Over Current or differential) or High Side Fuse	□ Transformer Differential □ Fault Pressure □ Time/Inst. Over Current	□ Transformer Primary Differential □ Transformer Backup Differential □ Fault Pressure □ Time/Inst. Over Current □ Over Excitation

Notes:

i. For transformers needing two differential protection schemes, one of the differential schemes may also include the generator.
ii. Generators must include protection to detect a loss of phase condition.

19.3. Interconnection Feeder Protection

The protection applied to a line terminal at the Generator Owner's site that interconnects the privately-owned generator with the PHI Power Delivery System will vary depending on the voltage class and existing line relaying scheme at the Company end(s). Typical protection schemes for various voltage interconnection lines are provided below. The actual schemes used will vary for each specific site.

Typical Line Terminal Protection Schemes Line Voltage Class	Line Protection Schemes
34kV and below	□ Phase & Ground Over current (may need to be directional) □ 3-Phase to Ground Connected Under Voltage & Over Voltage (For line terminating in delta or ungrounded wye connected transformer)

19.4. Utility Islanding Prevention Schemes

- Generators selling into the PJM marketplace that have their under-frequency trip point set to meet PJM under frequency operational requirements (such as 57.5 Hz. for 5 Seconds) essentially removes under frequency sensing as a sensitive means to detect isolation. In this case, other protective measures, such as transfer trip, will be required.
- In cases where a transfer trip scheme is needed to ensure isolation detection, the failure of the transfer trip scheme or communication channel will require that the generator automatically disconnect from the Company until the transfer trip scheme is restored.
- If a generator back feeds a substation distribution transformer with an ungrounded high side winding, a transfer trip scheme will be required. Any inverter installation greater than or equal to 750 kW will require DTT except when a substation DER overlimit scheme is installed. Any synchronous or induction machine installation greater than or equal to 250KW will require transfer trip.
- Transfer trip schemes shall only utilize a fiber path or leased 3rd party T1 line path as a communication medium.

19.5. DER Generator Protection Schemes

- The protection schemes on generators will become more complex as the size of the generator unit increases. In addition, those generators selling into the PJM marketplace will require specific protection as required by PJM. The PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards should be consulted.
- Multi-function microprocessor relays can be used to provide several generator protection functions. However, a second multi-function relay is necessary to provide for a relay failure.
- The Generator Owner should consult the generator manufacturer and national standards to develop the appropriate protection for each generator installation. National standards include C37.102-2006 IEEE Guide for AC Generator Protection and C37.101-2006 IEEE Guide for Generator Ground Protection.
- Some typical protection schemes for various size generators are noted in the following table. The actual schemes required for each site could vary from these representative samples.

Typical Generator Protection Schemes			
DC Generating Systems with Non-Islanding Inverters	**Induction/ Synchronous Generators Up to 10 MW**	**Synchronous Generators 10 MW - 50 MW**	**Synchronous Generators 50 MW+**
☐ Over/Under Voltage ☐ Over/Under Frequency (This preceding protection is integral to the Non-Islanding Inverter.) ☐ DC Over current	☐ Over/Under Voltage ☐ Over/Under Frequency ☐ Directional Power (watt / var) ☐ Phase Over current ☐ Ground Over current ☐ Negative Sequence	☐ Over/Under Voltage ☐ Over/Under Frequency ☐ Differential ☐ Stator Ground ☐ Loss of Field ☐ Anti-Motoring ☐ Negative Sequence ☐ Voltage Controlled. Over current	☐ Over/Under Voltage ☐ Over/Under Frequency ☐ Primary Differential ☐ Back Up Differential ☐ 100% Stator Ground ☐ Back Up Stator Ground ☐ Generator Lead Protection ☐ Primary Loss of Field ☐ Back Up Loss of Field ☐ Field Ground ☐ Anti-Motoring ☐ Negative Sequence ☐ Voltage Controlled Over current or Distance Backup ☐ Breaker Flashover ☐ Protection During Unit Start Up & Shut Down ☐ Accidental Energization ☐ Out of Step Protection ☐ Synchronizing Check

Notes:

iii. On generators with primary and backup differentials, one differential may also cover the unit step up transformer.
iv. Loss of synchronism (out-of-step) protection is necessary where stability studies have shown this protection to be needed.
v. Ancillary protection schemes such as breaker failure are also required.

19.6. Closed Transition Switching Installations

Generators that are normally interconnected in a non-synchronous manner, such as those used for load reduction, may be paralleled momentarily with the PHI Power Delivery System during part of a source or load transfer sequence.

If the time of momentary parallel operation with the EPS exceeds 300 seconds or is not performed as part of a commissioning test, these installations must meet the voltage ride through, frequency ride through and synchronization requirements outlined in appendix H and section 5.10.1.

20. Appendix F: Commissioning Checklist

Commissioning Checklist Prior To Energization for any Project with Upgrades or Operating Requirements

4 weeks prior to energization the Operation Control Center (OCC) requires:

- An energization request known as an administration order clearly stating the purpose of the request and all equipment involved listed along with their respective grid numbers.

The following can be provided by hard copy or PDF:

- The design drawing
- The one-line with the POI clearly marked
- A copy of the Interconnection Agreement

Prior to energization:

- All required equipment and upgrades must be in place and fully operational
- Equipment release forms must be filled out and submitted to the OCC

Additional requirements may be needed for certain Projects

This Commissioning Checklist provides evaluation and test requirements that are common to the range of DER configurations. Not all configuration possibilities are covered. Many DER performance requirements map to DER plant evaluation in 1547 section 11. Others are site- and utility feeder- and protection-related. Subsets of this list may be used for different projects.

	Requirement	Description
Config 1A –Less than or equal to 25 kW, Inverter, lab certified, exporting or non-exporting, radial distribution system) (PoC)		
☐	Documentation Matches Installation	Documentation must be consistent with the as-built installation.
☐	Inadvertent Energization	May be required if documentation is not clear about protecting against inadvertent energization.
☐	Enter Service	May be required if documentation is not clear about meeting enter service requirements.
Config 1B –Less than or equal to 25 kW, rotating machine, not lab certified, exporting or non-exporting, (PoC)		
☐	Documentation Matches Installation	Documentation must be consistent with the as-built installation.
☐	Cease to Energize Performance Requirement	If system has not been completely tested confirmation of cease to energize performance may be required.
☐	Control Capability Requirements	If system has not been completely tested confirmation of the DER control capabilities may be required.
☐	Enter Service Criteria	If system has not been completely tested, confirmation that DER meets enter service criteria may be required.
☐	Voltage and Reactive Power Control	Confirmation that DER meets voltage and reactive power control requirements is required.

PHI DER Technical Interconnection Requirements

	Requirement	Description
☐	Low and High Voltage Ride-Through	If system has not been completely tested, confirmation that DER meets low and high voltage ride-through requirements may be required.
☐	Frequency – Mandatory Trip and Frequency-Droop Requirements	If system has not been completely tested, confirmation that DER meets frequency trip and droop requirements may be required.
☐	Power Quality Requirements	If system has not been completely tested, confirmation that DER meets power quality requirements may be required.
Config 2B –25-250 kW DER Unit/System lab certified, Non-Exporting, Radial System (PoC)		
☐	Documentation Matches Installation	Documentation must be consistent with the as-built installation.
☐	Inadvertent Energization	May be required if documentation is not clear about protecting against inadvertent energization.
☐	Enter Service	May be required if documentation is not clear about meeting enter service requirements.
Config 2A –25-250 kW DER Unit/System lab certified, Exporting, Radial System (PoC)		
☐	Documentation Matches Installation	Documentation must be consistent with the as-built installation.
☐	Inadvertent Energization	May be required if documentation is not clear about protecting against inadvertent energization.
☐	Enter Service	May be required if documentation is not clear about meeting enter service requirements.
Config 3D - Greater than 250 kW and less than or equal to 500 kW DER Unit/System Not Completely lab certified, Non-Exporting, Radial System		
☐	Documentation Matches Installation	Documentation must be consistent with the as-built installation.
☐	Cease to Energize Performance Requirement	If system has not been completely tested confirmation of cease to energize performance may be required.
☐	Control Capability Requirements	If system has not been completely tested confirmation of the DER control capabilities may be required.
☐	Enter Service Requirements	If system has not been completely tested confirmation of the DER to meet Enter Service requirements may be required.
☐	Reactive Power and Voltage Control Requirements	If system has not been completely tested confirmation of the DER to meet reactive power and voltage control requirements may be required.
☐	Faults and Open Phase Conditions	If system has not been completely tested confirmation of the DER capabilities to open under fault and open phase conditions may be required.
☐	Voltage Trip Requirements	If system has not been completely tested confirmation of the DER capabilities to trip to meet voltage trip requirements may be required.

PHI DER Technical Interconnection Requirements

	Requirement	Description
☐	Low and High Voltage Ride-Through Requirements	If system has not been completely tested it may be required to confirm that the DER meet low and high voltage ride-through requirements.
☐	Frequency Trip Requirements	If system has not been completely tested confirmation of the DER capabilities to trip to meet frequency trip requirements may be required.
☐	Low and High Frequency Ride-Through Requirements	If system has not been completely tested it may be required to confirm that the DER meet low and high frequency ride-through requirements.
☐	Frequency – Mandatory Trip and Frequency-Droop Requirements	If system has not been completely tested, confirmation that DER meets frequency trip and droop requirements may be required.
☐	Power Quality Requirements	If system has not been completely tested, confirmation that DER meets power quality requirements may be required.
☐	Telemetry Requirements	Tests are required to confirm that telemetry requirements are met.
☐	Reverse Power Protection	Tests confirming reverse power protection shall be performed.
Config 4A Greater than 2 MW, DER Unit/System lab certified, Exporting, Radial System (PCC)		
☐	Documentation Matches Installation	Documentation must be consistent with the as-built installation.
☐	Cease to Energize Performance Requirement	If system has not been completely tested confirmation of cease to energize performance may be required.
☐	Control Capability Requirements	If system has not been completely tested confirmation of the DER control capabilities may be required.
☐	Faults and Open Phase Conditions	If system has not been completely tested confirmation of the DER capabilities to open under fault and open phase conditions may be required.
☐	Voltage Trip Requirements	If system has not been completely tested confirmation of the DER capabilities to trip to meet voltage trip requirements may be required.
☐	Frequency Trip Requirements	If system has not been completely tested confirmation of the DER capabilities to trip to meet frequency trip requirements may be required.
☐	Power Quality Requirements	If system has not been completely tested, confirmation that DER meets power quality requirements may be required.

PHI DER Technical Interconnection Requirements

Config 4B - Greater than 2 MW and less than or equal to 10 MW, DER Unit/System lab certified, Non-Exporting, Radial System (PCC)		
☐	Documentation Matches Installation	Documentation must be consistent with the as-built installation.
☐	Cease to Energize Performance Requirement	If system has not been completely tested confirmation of cease to energize performance may be required.
☐	Control Capability Requirements	If system has not been completely tested confirmation of the DER control capabilities may be required.
☐	Faults and Open Phase Conditions	If system has not been completely tested confirmation of the DER capabilities to open under fault and open phase conditions may be required.
☐	Voltage Trip Requirements	If system has not been completely tested confirmation of the DER capabilities to trip to meet voltage trip requirements may be required.
☐	Frequency Trip Requirements	If system has not been completely tested confirmation of the DER capabilities to trip to meet frequency trip requirements may be required.
☐	Power Quality Requirements	If system has not been completely tested, confirmation that DER meets power quality requirements may be required.
☐	Reverse Power Protection	Tests confirming reverse power protection shall be performed.

PHI DER Technical Interconnection Requirements

Config 4C - Greater than 2 MW and less than or equal to 10 MW DER Unit/System Not Completely lab certified, Exporting, Radial System (PCC)		
☐	Documentation Matches Installation	Documentation must be consistent with the as-built installation.
☐	Cease to Energize Performance Requirement	If system has not been completely tested confirmation of cease to energize performance may be required.
☐	Control Capability Requirements	If system has not been completely tested confirmation of the DER control capabilities may be required.
☐	Enter Service Requirements	If system has not been completely tested confirmation of the DER to meet Enter Service requirements may be required.
☐	Reactive Power and Voltage Control Requirements	If system has not been completely tested confirmation of the DER to meet reactive power and voltage control requirements may be required.
☐	Faults and Open Phase Conditions	If system has not been completely tested confirmation of the DER capabilities to open under fault and open phase conditions may be required.
☐	Voltage Trip Requirements	If system has not been completely tested confirmation of the DER capabilities to trip to meet voltage trip requirements may be required.
☐	Low and High Voltage Ride-Through Requirements	If system has not been completely tested it may be required to confirm that the DER meet low and high voltage ride-through requirements.
☐	Frequency Trip Requirements	If system has not been completely tested confirmation of the DER capabilities to trip to meet frequency trip requirements may be required.
☐	Low and High Frequency Ride-Through Requirements	If system has not been completely tested it may be required to confirm that the DER meet low and high frequency ride-through requirements.
☐	Frequency – Mandatory Trip and Frequency-Droop Requirements	If system has not been completely tested, confirmation that DER meets frequency trip and droop requirements may be required.
☐	Power Quality Requirements	If system has not been completely tested, confirmation that DER meets power quality requirements may be required.
☐	Telemetry Requirements	Tests are required to confirm that telemetry requirements are met.
Other configurations		
☐	Commissioning requirements to be determined by PHI on a case-by-case basis	

21. Appendix G: Telemetry Options (to be determined when transfer trip not required)

Communication Options for Plants ≥ 2 MW

Type	Benefits	Risk	Costs	Timing
Fiber - PHI installed	- Ensure scope, cost, and schedule	- Higher costs	- Included in Study estimates	Per PHI construction schedule
	- Highly reliable x5 - 9's	- Required to run fiber to substation		
		- Single spur is less reliable		
		- Railroad crossing permitting		
Wireless RADWIN	- PHI has infrastructure available	- Separate pole required at IC location	- Provided during detailed engineering	Per PHI construction schedule
	- High bandwidth, low latency	- Site survey required to determine availability		
	- Three 9's availability			
Fiber Ethernet (Carrier) - 3rd Party Install	- Reduced Cost from PHI fiber to install due to potential closer connection point	- Higher costs	- 3rd party estimates	3rd party construction schedule
		- Required to run fiber to substation	- Install costs	
		- Monthly fees	- Ongoing lease costs	
		- Single spur limits redundancy options	- Router & Firewall Install	
		-Railroad crossing permitting	- Router & Firewall O&M	
Wireless Radio Network (MAS, SSN)	Not an option today due to 5-minute pole cycle			

PHI DER Technical Interconnection Requirements

Type	Benefits	Risk	Costs	Timing
Jet Stream - public Internet with firewall behind it - direct to PJM	- Satisfies the need for limited real-time telemetry but not for revenue meter sharing.	- Limited number of projects allowed to be installed	- 3rd party estimates	3rd party construction schedule
		- Only allows limited operational data	- Install costs	
		- Data would come to PHI SCADA through ICCP link	- Ongoing lease costs	
		- Requires carrier ethernet connection	- Router & Firewall Install	
		- Back to back firewall required	- Router & Firewall O&M	
		- Monthly fees		
		- Need PJM to provided limited data		
Cellular (LTE) not an option today due to a 5-minute pole cycle	- Low cost	- Polling rates exceed the allowable rates	- Outdoor antenna normally side wall mounted	Per PHI construction schedule
	- Ease of installation	- Risk of disconnection, if rates exceed limits	- Antenna cable	
	- With advent of 5G the polling rate for machine to machine should go away	- No SLA from carrier	- Router and firewall	
		- Need to verify there is signal in the area		
		- Carrier coverage area is unknown		
		- Carrier maintenance unknown		

22. Appendix H: PHI Default Utility Required Profile (DU-URP) Settings

PHI Smart Inverter Settings for Distributed Generators

PHI Distribution Utility – Utility Required Profile (DU-URP) – Effective Jan. 1, 2024[22]

<table>
<tr><th colspan="2">Function</th><th colspan="2">IEEE 1547-2018 Performance Category</th></tr>
<tr><td colspan="2">Ride-Through</td><td colspan="2">Category III (Ride-Through) - Covers all bulk electric system reliability needs to avoid widespread DG tripping for disturbances for which the bulk system generators are expected to remain connected. Aligns with North American Electric Reliability Corporation (NERC) Standard PRC-024-2 for Generator Frequency and Voltage Protective Relay Settings.</td></tr>
<tr><td colspan="2">Voltage Regulation</td><td colspan="2">Category B (Voltage Regulation) - DGs have an extended set of voltage capabilities designed to offset the impacts of high local penetrations of DGs or individual DGs that have outputs that are time-varying.</td></tr>
<tr><th>Function</th><th>Description</th><th>Default Activation Status</th><th>IEEE 1547-2018 Setting</th></tr>
<tr><td>Anti-Islanding</td><td>Refers to the ability to detect loss of utility source and cease to energize</td><td>Activated</td><td>Trip within 2 seconds of the formation of an unintentional island</td></tr>
<tr><td>Constant Power Factor Mode</td><td>Refers to power factor set to a fixed value</td><td>Deactivated</td><td>Not applicable to DU-URP</td></tr>
</table>

[22] Any inverter replacements after Jan. 1, 2024 or otherwise enforced date shall be subjected to these requirements.

Function	Description	Default Activation Status	IEEE 1547-2018 Setting
Voltage / Reactive Power Mode (Volt - Var)	Refers to control of reactive power output as a function of voltage	*Activated*	*When in this mode, the DER shall actively control its reactive power output as a function of voltage following a voltage-reactive power piecewise linear characteristic.* *As specified by PHI in Table 1 of this document, the voltage-reactive power characteristic shall be configured using values in the optional adjustable range. The voltage-reactive power characteristics shall be adjustable locally and/or remotely as specified by the Area EPS operator.*
Enter Service Criteria	Refers to applicable system voltage, frequency and synchronization parameters when entering service and ramp rate performance during entering service	*Activated*	*When entering service, the DG shall not energize the Area EPS until the applicable voltage and system frequency are within the ranges specified in the defaults on Table 4 of IEEE 1547-2018.* *The DG ramp rate performance during entering service is specified in Section 4.10.3 of IEEE 1547-2018.* *The synchronization parameter limits for synchronous interconnection when entering service are specified in Table 5 of IEEE 1547-2018.*

<table>
<tr><th>Function</th><th>Description</th><th>Default Activation Status</th><th>IEEE 1547-2018 Setting</th></tr>
<tr><td>Voltage Ride Through</td><td>Refers to ability of smart inverter to ride through a certain range of voltages before tripping off</td><td>Activated</td><td rowspan="2">Refer to PJM Guideline for Ride Through Performance of Distribution-Connected Generators (Revision 2, Q4, 2019)

Setting requirements specified for Over-voltage, Under-voltage, Over-frequency and Under-frequency settings

Category II/III defaults for Frequency Ride Through

Category III functions with Category II default settings</td></tr>
<tr><td>Frequency Ride Through</td><td>Refers to ability of smart inverter to ride through a certain range of frequencies before tripping off</td><td>Activated</td></tr>
<tr><td>Voltage - Active Power Mode (Volt - Watt)</td><td>Refers to control of real power output as a function of voltage</td><td>Deactivated</td><td>Not applicable to PHI DU-URP</td></tr>
<tr><td>Constant Reactive Power Mode</td><td>Refers to reactive power set to a fixed value</td><td>Deactivated</td><td>Not applicable to PHI DU-URP</td></tr>
<tr><td>Frequency - Droop (Frequency - Power)</td><td>Refers to control of real power as a function of frequency</td><td>Activated</td><td>Adopt default settings in Table 24 of IEEE 1547-2018
This function is mandatory for Category II and Category III Ride-Through Performance in IEEE 1547-2018.</td></tr>
<tr><td>Active Power / Reactive Power Mode (Watt -Var)</td><td>Refers to the control of reactive power as a function of real power</td><td>Deactivated</td><td>Not applicable to PHI DU-URP</td></tr>
<tr><td>All Other Smart Inverter Settings</td><td>Refers to any other inverter settings/ activation status</td><td>As Applicable</td><td>All other smart inverter settings use applicable defaults specified in IEEE 1547-2018</td></tr>
</table>

Table 1— PHI Default DU-URP Voltage-reactive power settings for normal operating performance Category A and Category B DER

Voltage-reactive power parameters	PHI DU-URP Default settings		Ranges of allowable settings	
	Category A	Category B	Minimum	Maximum
V_{Ref}	V_N	V_N	0.95 V_N	1.05 V_N
V_2	V_N	$V_{Ref} - 0.03\ V_N$	Category A: V_{Ref} Category B: $V_{Ref} - 0.03\ V_N$	V_{Ref} [c]
Q_2	0	0	100% of nameplate reactive power capability, absorption	100% of nameplate reactive power capability, injection
V_3	V_N	$V_{Ref} + 0.03\ V_N$	V_{Ref} [c]	Category A: V_{Ref} Category B: $V_{Ref} + 0.03\ V_N$
Q_3	0	0	100% of nameplate reactive power capability, absorption	100% of nameplae reactive power capability, injection
V_1	0.9 V_N	$V_{Ref} - 0.09\ V_N$	$V_{Ref} - 0.18\ V_N$	$V_2 - 0.02\ V_N$ [c]
Q_1 [a]	25% of nameplate apparent power rating, injection	44% of nameplate apparent power rating, injection	0	100% of nameplate reactive power capability, injection[b]
V_4	1.1 V_N	$V_{Ref} + 0.09\ V_N$	V_3+0.02 V_N [c]	$V_{Ref} + 0.18\ V_N$
Q_4	25% of nameplate apparent power rating, absorption	44% of nameplate apparent power rating, absorption	100% of nameplate reactive power capability, absorption	0
Open loop response time	10 s	5 s	1 s	90 s

[a]The DER reactive power capability may be reduced at lower voltage.
[b]If needed DER may reduce active power output to meet this requirement.
[c]Improper selection of these values may cause system instability.

Table 2— PHI Default DU-URP DER response (shall trip) to abnormal voltages for DER of abnormal operating performance Category III

Shall trip—Category III				
Shall trip function	**PHI DU-URP Default settings**[a]		**Ranges of allowable settings**[b]	
	Voltage (p.u. of nominal voltage)	**Clearing time (s)**	**Voltage (p.u. of nominal voltage)**	**Clearing time (s)**
OV2	1.20	0.16	fixed at 1.20	fixed at 0.16
OV1	1.10	2.0	1.10–1.20	1.0–13.0
UV1	0.88	10.0	0.0–0.88	21.0–50.0
UV2	0.45	0.32	0.0–0.50	2.0–21.0

[a]The Area EPS operator may specify other voltage and *clearing time* trip settings within the *range of allowable settings*, e.g., to consider Area EPS protection coordination.

[b]Nominal system voltages stated in ANSI C84.1, Table 1 or as otherwise defined by the Area EPS operator. The *ranges of allowable settings* do not mandate a requirement for the DER to ride through this magnitude and duration of abnormal voltage condition. The Area EPS operator may specify the voltage thresholds and maximum *clearing times* within the *ranges of allowable settings*; settings outside of these ranges shall only be allowed as necessary for DER equipment protection and shall not conflict with the voltage disturbance ride-through requirements specified in 6.4.2 of IEEE 1547-2018. For the overvoltage (OV) and undervoltage (UV) trip functions *clearing time* ranges and for the OV trip functions voltage ranges, the lower value is a limiting requirement (the setting shall not be set to lower values) and the upper value is a minimum requirement (the setting may be set above this value). For the UV trip functions voltage ranges, the upper value is a limiting requirement (the setting shall not be set to greater values) and the lower value is a minimum requirement (the setting may be set to lower values).

23. Appendix I: PHI Impact/Facility Studies

A consolidated study shall be performed for level 4 application reviews (level 3 in NJ) and provided to the developer or customer in the below format. The consolidate study shall serve as a combined impact and facility study report. PHI may provide an abbreviated version of this report that may serve as a feasibility study. In some cases, a combined impact and facility study may not be sufficient. In those scenarios, a separate impact study will be conducted that will include electromagnetic transient analysis, transmission level analysis, load flow time series analysis or other types of analysis.